

4-December-2020

David Albright  
Manager, Groundwater Protection Section  
U.S. Environmental Protection Agency, Region IX  
75 Hawthorne Street  
San Francisco, California 94105

RE: Response to Technical Evaluation Comments and Information Request  
#4 for Underground Injection Control (UIC) Permit Application Class VI  
Pre-Construction Permit Application No. R9UIC-CA6-FY20-1

Dear Mr. Albright,

Clean Energy Systems, Inc. (CES) thanks you and the staff at the United States Environmental Protection Agency (EPA) for your consideration and review of our Class VI Pre-Construction Underground Injection Control (UIC) Permit Application for the Mendota site. Please find the attached enclosures in response to your recent Technical Evaluation Comments and Information Request #4, dated 28-October-2020, covering the proposed testing and monitoring activities, and the proposed construction and plugging procedures provided in Attachments B, C, D, E, and G of the subject permit application. CES worked with technical experts at Schlumberger to develop the responses. For completeness, we directly responded EPA's Questions/ Requests within each Enclosure, in *green font*.

The enclosures are organized into multiple sections. The first provides additional information and clarifications based upon your feedback. The next sections address each of the EPA's Enclosures directly. Finally, the Appendices provide updated figures, schematics, and describes requested testing procedure and clarifications.

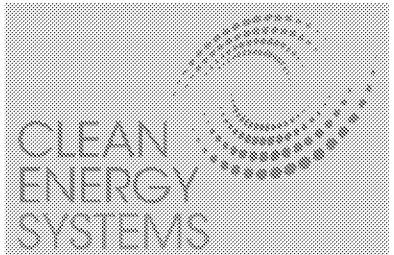
If you have any questions related to the content of this response or wish to discuss these matters further, I can be reached via email at [rhollis@cleanenergysystems.com](mailto:rhollis@cleanenergysystems.com).

Sincerely,



Rebecca M. Hollis  
CES Director of Business Development – CNE

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The Power to  
Reverse Climate  
Change

***Enclosures***

CC (via email): Keith Pronske, CES President & CEO  
Natalie Nowiski, Schlumberger NE CCS BD and Legal Counsel  
Vivian Rohrback, Schlumberger SIS Project Manager

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# 1 Introduction and Additional Information

*The EPA identified inconsistencies within Enclosures 1 and 2, which Clean Energy Systems (CES) would like to clarify. The CES clarifications are summarized in Table 1-1.*

*We have also included for reference, the regional geology and formation use at the Mendota site. Note this same information was also provided in CES Response #1 to EPA. Table 1-2 gives the formation descriptions and use, and Figure 1-1 shows the stratigraphy. These figures will be incorporated into the final version of the Narrative after all feedback is received from the EPA.*

*The rest of this document is organized as follows:*

- *Section 2 includes the CES responses to EPA questions, in green, for Enclosure 1.*
- *Section 3 includes the CES responses to EPA questions, in green, for Enclosure 2.*
- *Section 4, Appendix A, contains updated Enclosure 1 and Enclosure 2 figures and tables; the updates address EPA requests for clarification.*
- *Section 5, Appendix B, contains injection and gauge well schematics and casing, tubing, packer, and plugging descriptions. These include updated and new schematics that address EPA requests for clarification.*
- *Section 6, Appendix C, describes the falloff testing procedure and addresses a clarification request by EPA.*

Table 1-1. Summary of inconsistencies addressed.

### Summary of Inconsistencies Addressed

Section	EPA Inconsistency in Black Text	CES Clarification
2.1 Carbon Dioxide Stream Analysis	Two additional parameters related to injectate analysis are mentioned in some portions of the QASP: total hydrocarbons (THC, ppm v/v as CH <sub>4</sub> ) and sulfur dioxide (SO <sub>2</sub> , ppm v/v). For example, they are mentioned on pages 21 and 35; but are not included in the summary of analytical parameters for the CO <sub>2</sub> stream in the QASP (Table 6).	<i>Total hydrocarbons and sulfur dioxide are not relevant to the injectate analysis and have been removed from the QASP.</i>
2.2.1 Corrosion Monitoring	It appears that the carbon steel composition of the coupon for corrosion monitoring of the long-string casing (surface) in Table 5 (from Attachment C) is not representative of the materials, both chromium alloy steels, identified for the long-string casing in Table 2 (from Attachment G). It is not clear if the long-string casing (surface) listed in Table 5 would in fact be used at depth, given its label, and an equivalent surface long string casing is not listed in Table 2 of Attachment G.	<i>TN 95Cr13 is the proprietary grade for a tubing manufacturer (Tenaris) for a martensitic stainless steel with a 13% chrome content consistent with an L80-type 13% chrome material but modified for higher strength. As such, it is considered a chrome alloy. T-95 Type 1 is standard API grade nomenclature for API-defined tubulars in API 05CT. An updated version of Table 5 from attachment C with the correct long-string equipment coupon description is included in this document.</i>
2.2.3 External MITs	At least one of the MITs must be an approved tracer survey such as an oxygen- activation log or a temperature or noise log, unless an alternate test is approved by the EPA Administrator.)	<i>Comment noted. Approved tracer surveys are planned to be run per Table 8: Mechanical Integrity testing (MIT)</i>
2.6.1 CO <sub>2</sub> Plume Monitoring	The Testing and Monitoring Plan is unclear as to whether time-lapse VSP surveys or 3D surface seismic surveys (or both) are planned. If CES only plans to perform time-lapse VSP, this monitoring activity will need to extend into the post-	<i>The proposed seismic methodology will be to first acquire a surface 3D seismic survey to image the horizons and faults in the study area. Modeling for the 3D VSP will then be performed to assess the</i>

	injection phase, and the imaging will need to encompass an area on the larger end of the range CES identifies in order to encompass the entire 2.5 square mile AoR.	<i>impedance contrasts expected downhole and the coverage map for the 3D VSP. If it is determined through modeling that the plume can be imaged with 3D VSP, then 3D VSP will be proposed as the seismic method for mapping the plume post-injection, with approval from EPA.</i>
3.1 Injection Well Construction	Tables 10 and 14 in the narrative provide casing design specifications and details. The text states that grades as L-80 for the intermediate casing and long string casing but T-95 is listed in the tables.	<i>Please refer to updated Table 4-3 in Appendix A for correct material types for the surface and intermediate strings.</i>
3.5 Injection Well Plugging Plan	Clarification on why EverCRETE is not planned to be used for plugging and abandoning the wells.	<i>The EverCRETE cement system was chosen specifically for the injection casing due to the thin annulus between the open hole and the outer diameter of the casing. The self-healing properties of the EverCRETE system enable the cement to endure during the stress of the injection process during the life of the well. Cement plugs are not subject to these types of stresses and, as such, do not require such a high-grade cement formulation.</i>
3.5 Injection Well Plugging Plan	The plugging procedures state that the test pressure should be maintained +/- 10% for 30 minutes in order to pass the test (page 8). The well test pressure during the plugging procedure should not change more than 5 percent in 30 minutes.	<i>The plugging procedures will be updated from “the test pressure should be maintained <math>\pm 10\%</math> for 30 minutes in order to pass the test (page 8)” to read “The well test pressure during the plugging procedure should not change more than <math>\pm 5\%</math> in 30 minutes.”</i>

Table 1-2: Formation description and intended use.

<b>Primary Formations of Interest</b>	<b>Formation Description and Intended Use</b>
<b>Garzas Sandstone</b>	The Garzas Sandstone member of the Moreno formation represents a major deltaic complex and overlies the Moreno Shale. This zone will be monitored for above-confining-zone migration of CO <sub>2</sub> .
<b>Moreno Shale</b> (Well correlation includes Ragged Valley Sub) <b>Secondary Confining Zone</b>	The Moreno Shale is an organic-rich marine shale. Because of the Moreno Shale's thickness (~1100 ft) and because it is regionally extensive, it is intended to provide a seal to ultimately contain any injected CO <sub>2</sub> that may be migrating up from the underlying First Panoche Sandstone.
<b>First Panoche Sandstone</b> <b>Secondary CO<sub>2</sub> Injection Zone</b> (Permission to inject into this formation is requested)	The First Panoche is intended to be a secondary injection zone to be used if the underlying Second Panoche is unsuitable for injection or if there is CO <sub>2</sub> migration that passes up through the below First Panoche Shale.
<b>First Panoche Shale</b> <b>Primary Confining Zone</b>	The First Panoche Shale is intended to be the primary confining zone that will vertically contain most or possibly all the injected CO <sub>2</sub> . Because it is relatively thin (127 ft) and because its lateral continuity is unproven, this formation is not being relied upon to contain all the injected CO <sub>2</sub> . Currently, this formation is interpreted to be continuous within the model domain.
<b>Second Panoche Sandstone</b> <b>Primary CO<sub>2</sub> Injection Formation</b> (Permission to inject into this formation is requested)	The Second Panoche sandstones are the primary target for CO <sub>2</sub> injection.
<b>Third Panoche</b> <b>Potential CO<sub>2</sub> Injection Formation</b> (Permission to inject into this formation is requested)	Although not the target of this project currently, this formation may have potential in the future for CO <sub>2</sub> injection. The lower permeability of this formation will likely make this a lower confining zone.
<b>Third Panoche Shale</b> <b>Lowest Confining Formation</b>	The shales of the Third Panoche are intended to act as the lowermost confining zone.
<b>Fourth Panoche</b> <b>Potential CO<sub>2</sub> Injection Formation</b>	Although not the target of this project currently, this formation may have potential in the future for CO <sub>2</sub> Injection.



Schlumberger-Private

## 2 Enclosure 1

### Evaluation of Proposed Testing and Monitoring Activities at the CES-Mendota Class VI Project

This testing and monitoring evaluation report for the proposed Clean Energy Systems (CES)-Mendota Class VI geologic sequestration project summarizes EPA's evaluation of the testing and monitoring CES proposes to conduct during and following injection operations. Due to the similarities of certain monitoring activities (e.g., groundwater monitoring and plume and pressure front tracking) to be performed in the injection and post-injection phases, these activities (as described in Attachments C and E of the Class VI permit application) are evaluated in a single report. This review also identifies preliminary questions for CES.

CES notes that they will report the results of all injection-phase testing and monitoring activities in compliance with the requirements of 40 CFR 146.91. The results of post-injection testing and monitoring results will be submitted to EPA in annual reports within 60 days following the anniversary date of the date on which injection ceases.

#### 2.1 Carbon Dioxide Stream Analysis

CES will sample the carbon dioxide (CO<sub>2</sub>) stream on a quarterly basis at a location after the last stage of compression. The table below summarizes the analytical parameters that CES proposes for monitoring the CO<sub>2</sub> stream (from Table 1).

Parameter	Analytical Method(s) <sup>1</sup>
Oxygen	ISBT 4.0 (GC/DID) GC/TCD
Nitrogen	ISBT 4.0 GC/DID GC/TCD
Carbon Monoxide	ISBT 5.0 Colorimetric ISBT 4.0 (GC/DID)
Oxides of Nitrogen	ISBT 7.0 Colorimetric
Ammonia	ISBT 6.0 (DT)
Hydrogen Sulfide	ISBT 14.0 (GC/SCD)
CO <sub>2</sub> Purity	ISBT 2.0 Caustic absorption Zahm-Nagel ALI method SAM 4.1 subtraction method (GC/DID) GC/TCD

Note 1: An equivalent method may be employed with the prior approval of the UIC Program Director.

There are no EPA-approved analytical methods for CO<sub>2</sub> injection streams. The analytical methods CES proposes to use appear to be from the International Society of Beverage Technologists (ISBT). All of these analytical methods, except ISBT 6.0 have been employed for other CO<sub>2</sub> GS projects, so there is EPA precedent for their use in EPA Class VI permits.

Most of the proposed analytical parameters match the results of a gas stream analysis that is presented in Table 8 of the permit application narrative (replicated below). The application notes that the gas stream will contain 96.78% CO<sub>2</sub> with some impurities. It is unclear when this sample was taken.

Injectate Composition (Mass Fractions) From Table 8 of the permit application	
H <sub>2</sub> O	0.002245
O <sub>2</sub>	0.011536
H <sub>2</sub>	0.000164
N <sub>2</sub>	0.001475
CO	0.005322
CO <sub>2</sub>	0.967834
Ar	0.01119
NO	9.01E-05
NO <sub>2</sub>	9.03E-08
H <sub>2</sub> S	0.000144
NH <sub>3</sub>	1.93E-10

QA procedures for all of the analytical parameters proposed for the CO<sub>2</sub> stream analysis are documented and described in the QASP (Section A4a). Two additional parameters related to injectate analysis are mentioned in some portions of the QASP: total hydrocarbons (THC, ppm v/v as CH<sub>4</sub>) and sulfur dioxide (SO<sub>2</sub>, ppm v/v). For example, they are mentioned on pages 21 and 35; but are not included in the summary of analytical parameters for the CO<sub>2</sub> stream in the QASP (Table 6).

**Questions/Requests for CES:**

- *In addition to the proposed injectate analytical parameters identified in Table 1 of the Testing and Monitoring Plan, argon and H<sub>2</sub> were detected in the analytical sample described on Table 8 of the permit application narrative. Please include these in the Testing and Monitoring Plan or explain why analyses for these parameters is not warranted.*
- *Ar and H<sub>2</sub> will be added to the testing and monitoring plan (Table 1 of Attachment C) based on the current CO<sub>2</sub> injectate composition. The injectate analytical parameters shown in the testing and monitoring plan (Table 1 of Attachment C) will be updated according to the final CO<sub>2</sub> injectate composition approved by EPA prior to injection.*
- *Total hydrocarbons and sulfur dioxide (SO<sub>2</sub>) are mentioned as part of the QA procedures for injectate analysis in the QASP, but they are not on Table 1 in Attachment C. If these are not to be part of the injectate analysis, please remove them from the QASP.*
- *Total hydrocarbons and sulfur dioxide were included in the QASP as part of the QA procedures and are not relevant to injectate analysis. They have been removed from the QASP.*
- *What is the date of the injectate characterization sample presented on Table 8 of the permit application narrative? EPA will require another baseline injectate sample be analyzed prior to commencement of injection.*
- *The composition of the CO<sub>2</sub> stream shown in Table 8 of the permit application narrative is based on a process model completed in December 2019. Baseline injectate samples will be collected and analyzed. The results will be submitted to the EPA for approval prior to injection.*

**Considerations based on the results of Pre-Operational Testing/Modeling Updates:**

- *If the geochemical modeling evaluation indicates that any injectate constituents may lead to*

*geochemical reactions that could affect operations or change aquifer properties, additional analytical parameters for the injectate analysis may be warranted.*

- *If the geochemical modeling evaluation indicates potential geochemical reactions or impact to the aquifer, additional parameters will be requested to be added to the analysis.*

## 2.2 Injection Well Testing

The subsections below describe the planned quarterly corrosion monitoring; continuous recording of injection pressure, rate, and volume to evaluate internal mechanical integrity; and annual external MITs that will meet the requirements at 40 CFR 146.90(b), (c), and (e).

### 2.2.1 Corrosion Monitoring

CES proposes to conduct corrosion monitoring using the coupon method. The coupons will be exposed to conditions similar to those in the borehole, in a parallel flow-through pipe arrangement containing the stream of high-pressure CO<sub>2</sub> at a location downstream of processing equipment and just upstream of actual injection into the well. According to CES, the samples will be handled and assessed in accordance with ASTM G1-03. The coupons will be inspected prior to testing and will be removed and inspected on a quarterly basis. Inspection equipment will be able to dimensionally measure at a tolerance of 0.0001 inches, to weigh at a tolerance of 0.0001 gram, and to photograph or visually inspect at a level of at least 10X magnification.

The proposed coupons will be composed of the materials summarized in Attachment C, Table 5, as excerpted below:

*List of equipment coupons with material of construction (Table 5 of Attachment G)*

<b>Equipment Coupon</b>	<b>Material of Construction</b>
Pipeline	Carbon Steel
Long String Casing	Carbon Steel
Long String Casing	Chrome Alloy
Injection Tubing	Chrome Alloy
Wellhead	Chrome Alloy
Packer	Chrome Alloy

The materials identified for corrosion monitoring were compared to the list of proposed construction materials for the injection well, Mendota\_INJ\_1, and are shown in Attachment G, Table 2, *Casing Specifications*, Table 3, *Packer Specifications*, and Table 4, *Injection Tubing Specifications*, and excerpted below:

*Casing specifications (Table 2 of Attachment G)*

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Thermal Conductivity @ 77°F (BTU/ft in op)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	86	22	21	197.41	B	Welded	26.13	2440	1950
Surface	1860	16	15.01	84	N80	Long	26.13	4330	1480
Intermediate	7432	10.75	9.760	55.5	N80	Long	26.13	6450	4020
Long-string	7332	7	5.920	38	T-95 Type 1	Long	26.13	12830	13430
Long-string	10412	7	5.920	38	TN 95Cr13	Long	14.92	12830	13430

As noted in Table 2 of Attachment G, the conductor, surface, and intermediate casing will be composed of carbon steel, grades B and N80. The long-string casing will be composed of alloy steel, grades T-95 and TN 95, containing relatively high chrome content.<sup>1</sup>

It appears that the carbon steel composition of the coupon for corrosion monitoring of the long-string casing (surface) in Table 5 (from Attachment C) is not representative of the materials, both chromium alloy steels, identified for the long-string casing in Table 2 (from Attachment G). It is not clear if the long-string casing (surface) listed in Table 5 would in fact be used at depth, given its label, and an equivalent surface long string casing is not listed in Table 2 of Attachment G.

- TN 95Cr13 is the proprietary grade for a tubing manufacturer (Tenaris) for a martensitic stainless steel with a 13% chrome content consistent with an L80-type 13% chrome material but modified for higher strength. As such, it is considered a chrome alloy. Please refer to Tenaris' website for further information (<https://www.tenaris.com/en/products-and-services/octg/steel-grades>).*
- T-95 Type 1 is standard API grade nomenclature for API defined tubulars in API 05CT.*
- There is an error on the long-string equipment coupon description in Table 5 of Attachment G and has been corrected. See Table 4-1 in Appendix A of this document for the updated table.*

*Tubing specifications (Table 3 of Attachment G)*

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Thread)	Burst strength (psi)	Collapse strength (psi)
Injection tubing	9430	3.5	2.992	9.2	L80Cr13	Long	10160	10540

The proposed injection tubing for the injection well will be composed of L80Cr13, or Cr13L80, an alloy steel with high chromium content, for which the proposed coupon in Table 5 is representative.

*Packer specifications (Table 4 of Attachment G)*

<sup>1</sup> <https://www.contalloy.com/products/grade/t95>  
<https://metals.ulprospector.com/datasheet/e226076/tenaris-tn-95cr13>

Packer Type and Material	Packer Setting Depth (feet) (bgs)	Length (inches)	Nominal Casing Weight (lbs/ft)	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
Super 13Cr	9390	64	38	5.685	4.0
Tensile Rating (lbs)	Burst Rating (psi)	Collapse Rating (psi)	Max. Casing Inner Diameter (inches)	Min. Casing Inner Diameter (inches)	
133.12@250degF	5000	5000	6000	5.949	

Similarly, the coupon proposed in Table 5 for the packer is representative of the Super 13Cr steel alloy proposed for the packer in the injection well.

Although the materials of construction for the pipeline and wellhead are not described in Attachment G, it is assumed that coupons would be selected to represent these materials.

In addition to the corrosion monitoring described above, CES proposes to perform casing inspection logs (CILs) to measure the thickness of the injection well casing at the subsurface (as described on page 17 of Attachment C, and on pages 15 and 18 of Attachment G). (See also the summaries of MITs in Tables 5 and 6 of Attachment G.) The proposed CIL would be performed prior to injection, and at one year intervals thereafter. CES proposes the following logging tools for this testing: ultrasonic imaging (PowerFlex), magnetic flux leakage (MFL), casing bond log (CBL) and electro-magnetic imaging (EMIT). A reduction in thickness of more than 20% of API standard thickness would prompt further investigation.

#### *Questions/Requests for CES:*

- *Please revise the list of casing strings and materials in Attachment C, Table 5 to reflect Attachment G, Table 2, Casing Specifications. For example, please provide a coupon material representative of long string casing (surface) e.g., chrome alloy.*
- *Please refer to Appendix A, Table 4-1, for the list of equipment coupons with material of construction. (This is the updated Table 5 of Attachment G).*
- *Please provide the list of construction materials to be used for the pipeline and wellhead so that they can be compared to the proposed coupon materials for the corrosion testing program.*
- *The construction materials for the pipeline will be defined during FEL-2 study and will be provided to the EPA when available. The construction material for the wellhead will have a body of low-carbon-alloy 4130 steel with inlays covering the internal CO<sub>2</sub> wetted surfaces, and the wellhead will be constructed per NACE MR0175/ISO 15156 guidelines. Currently, that is thought to be a martensitic stainless steel 13Cr but is dependent on the final CO<sub>2</sub> stream composition and testing.*

### **2.2.2 Continuous Monitoring to Evaluate Internal Mechanical Integrity**

CES proposes continuous monitoring of temperature and pressure via gauges at three locations within the injection well: (1) at the surface, (2) in the tubing at the packer, and (3) from the surface to the tubing packer, via distributed temperature sensing (DTS) fiber. The continuous monitoring program is summarized in Table 2 of Attachment C, as excerpted below.

Monitoring Injection Rate and Pressure: injection rate and pressure will be monitored via the electronic temperature/pressures gauges connected to the distributive control system (DCS). The DCS will ensure that maximum pressure of **2,026 psi** at the surface and of **5,677 psi** at the bottom hole are not reached.

Monitoring Annular Pressure: the annulus will be filled with brine during injection operations. During injection, the surface injection pressure should always be at least **1,142 psi**, as noted on page 14 of Attachment C. During shutdown, the surface annulus pressure must maintain the 100 psi difference between the annulus and the casing. The proposed annulus monitoring system, composed of the continuous pressure gauge, the head tank, two sets of pressure regulators, and a flood level indicator, will maintain an annulus pressure between **1,100 and 1,200 psi** (see page 14 of Attachment C).

*Table 2: Sampling devices, locations, and frequencies for continuous monitoring.*

Parameter	Device(s)	Location	Min. Sampling Frequency	Min. Recording Frequency
Injection pressure		Surface	10 seconds	5 minutes (3)
Injection pressure		Reservoir - Proximate to packer	10 seconds	5 minutes (3)
Injection rate		Surface	10 seconds	5 minutes (3)
Injection volume		Surface	10 seconds	5 minutes (3)
Annular pressure		Surface	10 seconds	5 minutes (3)
CO <sub>2</sub> stream temperature		Surface	10 seconds	5 minutes (3)
Temperature		Reservoir - Proximate to packer	10 seconds	5 minutes (3)
Temperature/Acoustic	DTS/DAS	Along wellbore to packer	10 seconds	1 hour
Annulus fluid volume		Surface	4 hour	24 hour

It appears that the annulus pressure of **2,126 psig** proposed in the Table of Injection Well Operating Conditions, in Attachment A is higher than the range of pressures, of **1,100 psi to 1,200 psi**, to be maintained in the annual pressure monitoring system described in the Testing and Monitoring Plan (see bottom of page 14 of Attachment C).

*Questions/Requests for CES:*

- Please describe more explicitly the location/depth of the pressure/temperature gauges at the packer.
- Please refer to Figure 5-1 in Appendix B for a well schematic that includes gauge placement and type.
- Please explain the discrepancy between the annulus pressure to be maintained in the annulus monitoring system, of 1100 psi to 1200 psi, and the proposed operating annulus pressure of 2126 psi in Attachment A.
- The operating annulus pressure of 2126 psi is in error and should be 5777 psi. Monitoring annular pressure conditions at surface pressure of 500 psi will be initiated. This will be achieved by using a packer fluid of 10.9 pound per gallon (ppg) which would give a pressure of 5277 psi at the top of the packer. One of the purposes of the packer fluid is to kill the well quickly in the event of an uncontrollable leak. It is important to have a packer fluid with sufficient density to kill the well. Because this is an injection well there is potential for higher pressures than pore pressure coming back into the well, at least temporarily. For purposes of the permit, CES is assuming

*maximum injection pressure of 5677 psi. This means the packer fluid would need to be 10.9-ppg density with 500 surface pressure. A sustained 500 psi surface pressure is considered an optimal pressure for monitoring pressure at surface. Higher pressures create potentially more safety and operational risks. A 500 psi annular pressure will allow adequate monitoring of the expansion and contraction of the annular fluid due to temperature changes especially during injection. Potential annular fluid losses due to leaks and gas invasion from tubing or packer failure will be visible monitoring the 500 psi wellhead pressure. After an evaluation well is drilled, more comprehensive values can be given for pressures.*

### ***Considerations based on the results of Pre-Operational Testing/Modeling Updates:***

- The maximum pressure thresholds identified for continuous monitoring and the annulus pressure in Attachment C may need to be adjusted based on the determination of final permit conditions.*
- Comment noted. This will be reviewed when official permit conditions are provided.*

### **2.2.3 External MITs**

As described in the pre-operation testing plan in Sections 4 and 5 of Attachment G, in addition to deviation checks to be conducted during well construction, CES proposes to perform MITs in both the injection well and the deep monitoring wells (ACZ\_1 And OBS 1, which are described in the section on Groundwater Quality Monitoring below), in compliance with the regulatory requirements as summarized in Tables 5 and 6 of Attachment G, excerpted below.

*Summary of the Mendota\_INJ\_1 MITs and pressure fall-off tests to be performed prior to injection (Table 5 of Attachment G)*

<b>Class VI Rule Citation</b>	<b>Rule Description</b>	<b>Test Description</b>	<b>Program Period</b>
<b>40 CFR 146.89(a)(1)</b>	MIT - Internal	Pressure test	Prior to operation
<b>40 CFR 146.87(a)(4)</b>	MIT - External	Pressure test	Prior to operation
<b>40 CFR 146.87(a)(4)</b>	MIT - External	Casing inspection Ultrasonic and CBL	Prior to operation
<b>40 CFR 146.87(e)(1)</b>	Testing prior to operating	Pressure fall-off test	Prior to operation

*MITs to be performed on the deep monitoring well(s), MendotaOBS 1 and Mendota ACZ 1 (Table 6 of Attachment G)*

<b>Rule Description</b>	<b>Test Description</b>	<b>Program Period</b>
MIT - Internal	Pressure test	Prior to operation
MIT - External	Pressure test	Prior to operation
MIT - External	Casing inspection, EMIT, MFL, Ultrasonic and CBL	Prior to operation
Testing prior to operating	Pressure fall-off test	Prior to operation

During injection operations, CES proposes conducting at least one of four MITs to confirm external mechanical integrity as summarized in Attachment C, Table 8, which is excerpted below. (Note that, per 40 CFR 146.89(c), at least one of the MITs must be an approved tracer survey such as an oxygen-activation log or a temperature or noise log, unless an alternate test is approved by the EPA Administrator.)

- Comment noted. Approved tracer surveys are planned to be run per Table 8 of Attachment C,*

*mechanical integrity testing (MIT).*

**Table 8: Mechanical integrity testing (MIT).**

<b>Test Description</b>	<b>Location</b>
Temperature Log / Survey	Along wellbore using Distributed Temperature Sensing (DTS) or conventional wireline well log
Oxygen Activation Log	Wireline Well Log
Pulsed Neutron Logging	Wireline Well Log
Acoustic (or Noise) Log/Survey coupled with Temperature Log/Survey	Along wellbore using Distributed Acoustic Sensing (DAS); DAS equivalent or conventional wireline well log

Oxygen activation logging, temperature logging, or acoustic (or noise) logging procedures are described in Attachment C, Section 7.2.1.3 (oxygen activation), Section 7.2.1.1 (temperature), and Sections 7.2.1.5 and 7.2.1.6 (noise). In Section 7.2.1.4, CES proposes testing using pulsed neutron logging.

CES proposes performing these tests annually, which is consistent with the Class VI requirements. The proposed pulsed neutron logging would occur, as described on page 23 of Attachment C, on a quarterly basis for 18 months after authorization, and then annually.

#### **Questions/Requests for CES:**

- *Please justify the use of pulsed activation logging as an alternative tool, beyond the MITs described at 40 CFR 146.89(c), or clarify in the Testing and Monitoring Plan that at least one of the tests identified at 40 CFR 146.89(c) will be performed each year.*
- *CES proposes using multiple technologies to ensure external mechanical integrity of the injection and monitoring wells to provide the safe operation of the sequestration site and ensure nonendangerment to any USDW. Initial evaluation of the INJ 1 injection well and the OBS 1 and ACZ 1 monitoring wells will be done using casing and cement CBL and ultrasonic logs and pressure tests.*
- *The INJ 1 injection well and the OBS 1 and ACZ 1 monitoring wells will all be instrumented with DAS/DTS fiber and monitored continuously throughout the injection period. The distributed temperature and acoustics are to be evaluated over the reporting period for the monitoring wells. The temperature and acoustic (noise) survey for the INJ 1 injection well may be obscured by the injection operation. The INJ 1 injection well will be shut in, and a temperature and acoustic (noise) survey will be acquired quarterly during the first 1.5 years of injection and annually through the injection period. See Table 4-2 in Appendix A of this document.*
- *Pulsed neutron logs (PNL) have several measurements sensitive to CO<sub>2</sub> and can detect CO<sub>2</sub> in the formation and well annular spaces. PNL measurements can be made through multiple tubing and casing strings allowing monitoring of the well annuli and formation behind the completion tubing. This sensitivity, especially in time lapsed monitoring, allows detecting CO<sub>2</sub> introduction, change, or accumulation in the well annuli and associated to analyze mechanical integrity and assist in plume migration modeling. Additionally, PNL thermal decay (sigma) measurements are sensitive to salinity changes and can detect migration of water in the well annuli and formations. PNL logs will be acquired in the INJ 1 injection well. See Table 4-2 in Appendix A of this*

*document. OBS 1 and ACZ 1 monitoring wells will be monitored quarterly during the first 1.5 years of injection and annually through the injection period.*

## 2.3 Pressure Fall-Off Testing

CES described nearly identical PFOT procedures in the Testing and Monitoring Plan and in the Construction Plan (Attachment G). See the construction and plugging evaluation report for the results of our review of the PFOT procedures. At the conclusion of the reviews, the Testing and Monitoring Plan will need to be revised to address any issues identified.

### *Questions/Requests for CES:*

- The testing and monitoring plan quotes the Class VI Rule requirement that a PFOT be performed at least every 5 years. It also states (under “Timing of Falloff Tests and Report Submission”) that falloff tests must be conducted annually. Please clarify the planned frequency of PFOTs during the injection phase.
- *PFOT testing will occur every 5 years. The timing of falloff tests and report submissions will be updated accordingly.*

## 2.4 Groundwater Quality Monitoring

CES plans to monitor groundwater quality above the confining zone using direct and indirect methods.

### ***Direct Groundwater Quality Monitoring***

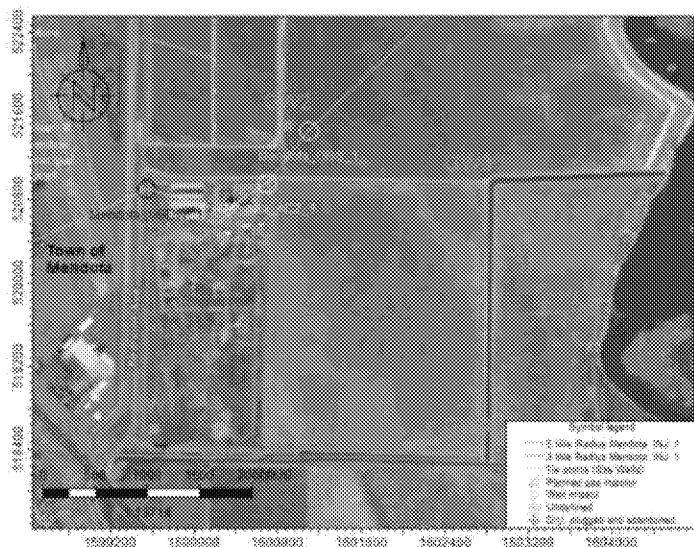
CES plans to perform direct groundwater quality monitoring via four (4) shallow groundwater monitoring wells (GW1, GW2, GW3, and GW4), a USDW monitoring well (USDW1), and an above confining zone monitoring well (ACZ1).

The approximate locations of the monitoring wells are shown on the map on the left in the figure below (from Figure 1 of Attachment C). The locations are preliminary and are expected to be refined as the project develops.

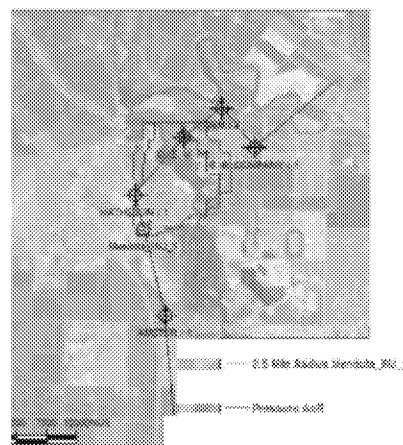
- GW1, GW2, GW3, and GW4 are shallow groundwater monitoring wells used to monitor the quaternary/shallow aquifers around the site that are sources of drinking water. CES plans to sample in one interval. The precise depths of these groundwater monitoring wells will be determined when the groundwater characteristics of the site are better understood, but they are expected to be somewhere between 50 and 500 feet deep.
- Mendota USDW 1 will be used to sample from the Santa Margarita or the base of the USDW, and it will be located within 1,000 feet of the injection well.

The ACZ1 monitoring well will be completed in the Garzas Formation or the first permeable sandstone above the Moreno Shale (confining zone). The well will be in the up-dip direction of the Moreno Formation, or in the event a potential fault is identified on the 3D seismic within the AoR CES states that “the well will be in the direction of the fault intersection of the Moreno formation.”

- In addition, the Mendota OBS 1 monitoring well will be completed in the Panoche Sand and will be used to monitor plume migration. See “CO2 Plume Monitoring,” below.



### Location of monitoring wells



### Delineated AoR

The map of monitoring well locations can be compared to the expected extent of the plume after 20 years, as shown on the map to the right of the figure above (from Figure 12 of Attachment B). While the scales of the maps in the plans are different, they have the same legend and it appears that the monitoring wells will be located within the defined AoR and in the anticipated direction of plume and pressure front movement. The suitability of these proposed locations will be refined as the AoR modeling evaluation proceeds.

CES indicates that the precise locations of the wells will be determined in future phases of the project (it is unclear what this means relative to construction of the injection well and pre-operational testing). However, the location and construction of the wells will need to be approved prior to issuing a Class VI permit. This is typically included with the permit to construct the injection well; if this is not possible, the permit will need to include conditions such that authorization to inject cannot be given until a separate review of the monitoring well locations and their construction is performed. CES should note that the Central Valley Water Board indicated that any newly drilled monitoring wells must be approved by the Water Board and, while existing wells would not need to be approved, the Water Board expressed interest in any plans to use existing wells as monitoring wells.

Groundwater quality monitoring above the confining zone will include baseline monitoring and monitoring during the injection and post-injection phases of the project:

- Baseline fluid sampling at the shallow monitoring wells (GW1, GW2, GW3, and GW4) and USDW 1 will occur quarterly for at least one year prior to injection.
- Baseline fluid sampling at Mendota ACZ 1 will occur during well construction and once prior to injection.
- Injection phase groundwater quality sampling and monitoring will be performed quarterly in GW1, GW2, GW3, GW4, and USDW 1 and annually in ACZ 1

- During the post-injection phase, monitoring in GW1, GW2, GW3, GW4, and USDW 1 will be quarterly for 3 to 5 years post-injection and then annually afterwards. Monitoring in ACZ 1 will be annual for years 1 through 3, then in years 5, 7, and 10 after injection ceases.

Table 6 shows the planned monitoring methods, locations, and frequencies for groundwater quality and geochemical monitoring above the confining

Table 7 of the Testing and Monitoring Plan (replicated below) identifies the analytical and field parameters for groundwater sampling above the confining zone. CES proposes to analyze for the same parameters in Table 2 of the PISC and Site Closure Plan. Groundwater quality analytical methods are all EPA-approved Methods and are addressed in the QASP.

The parameters appear to be appropriate for groundwater quality monitoring needs for GS projects, and are consistent with other Class VI monitoring programs. It is recommended that CES add zinc to the groundwater quality monitoring parameters to complement the monitoring of other commonly occurring heavy metals (Cu, Pb, Cr, Co). Note that, as additional information is gathered based on the reviews of other parts of the permit application or pre-operational data collection, recommendations or requirements for additional analytical parameters may be provided.

Parameters	Analytical Methods <sup>1</sup>
<b>Quaternary / Shallow strata sources of drinking water</b>	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, Zn, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO <sub>3</sub> , and SO <sub>4</sub>	Ion Chromatography, EPA Method 300.0 <sup>1</sup>
Dissolved CO <sub>2</sub>	Coulometric titration, ASTM D513-11
Total Dissolved Solids	Gravimetry; Method 2540 C [11]
Alkalinity	Method 2320 B [11]
pH (field)	EPA 150.1
Specific conductance (field)	Method 2510-B [11]
Temperature (field)	Thermocouple
<b>Santa Margarita or base of USDW</b>	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, Zn, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO <sub>3</sub> , and SO <sub>4</sub>	Ion Chromatography, EPA Method 300.0 <sup>1</sup>
Dissolved CO <sub>2</sub>	Coulometric titration, ASTM D513-11
Isotopes: 5 <sup>13</sup> C of DIC	Isotope ratio mass spectrometry
Total Dissolved Solids	Gravimetry; Method 2540 C [11]
Alkalinity	Method 2320 B [11]
pH (field)	EPA 150.1
Specific conductance (field)	Method 2510-B [11]

Temperature (field)	Thermocouple
<b>Garzas</b>	
Cations: Al, Ba, Mn, As, Cd, Cr, Cu, Pb, Sb Se, Zn, and Tl	ICP-MS, EPA Method 6020
Cations: Ca, Fe, K, Mg, Na, and Si	ICP-OES, EPA Method 6010B
Anions: Br, Cl, F, NO <sub>3</sub> , and SO <sub>4</sub>	Ion Chromatography, EPA Method 300.0 '1
Dissolved CO <sub>2</sub>	Coulometric titration, ASTM D513-11
Isotopes: 5°C of DIC	Isotope ratio mass spectrometry
Total Dissolved Solids	Gravimetry; Method 2540 C [11]
Alkalinity	Method 2320 B [11]
pH (field)	EPA 150.1
Specific conductance (field)	Method 2510-B [11]
Temperature (field)	Thermocouple

Note 1: ICP = inductively coupled plasma; MS = mass spectrometry; OES = optical emission spectrometry; GC-P = gas chromatography - pyrolysis. An equivalent method may be employed with the prior approval of the UIC Program Director.

## 2.5 Indirect Groundwater Quality Monitoring

Indirect groundwater quality monitoring activities above the confining zone will include DAS (distributed temperature/acoustic) monitoring and pulsed neutron monitoring in ACZ 1, OBS 1, and INJ 1 (the injection well). Following a baseline log, DAS monitoring will be continuous throughout injection phase and during the first three years of post-injection phase monitoring.

### Questions/Requests for CES:

- Please provide a map that shows the location of the monitoring wells at a scale that also shows the extent of the plume and pressure front (i.e., Figure 12 of Attachment B and Figure 1 of Attachment C at the same scale)
- Please refer to Figure 4-1 in Appendix A in this document, which is the replacement map combining maps from Figure 12 Attachment B and Figure 1 Attachment C.
- Table 6 indicates that quarterly monitoring in the shallow wells and USDWI will occur in years 1 and 2 of the injection phase. Please also specify the proposed frequency at which groundwater sampling will be performed in the remaining years of the injection phase.
- Please refer to Table 4-2 in Appendix A of this document, which updates the groundwater monitoring schedule from Table 6 in the original submission.
- EPA requests that CES include quarterly monitoring in ACZ1 in Table 6 (at least for the first 5 years of injection) since this is a porous formation right above the confining zone and is close to the injection well. Please revise Table 6 accordingly.
- Refer to Table 4-2 in the Appendix of this document, which updates Table 6 to reflect the change from continuous to quarterly monitoring for the first 5 years of injection.
- Please remove DAS and pulsed neutron monitoring from Table 6, as these are not groundwater monitoring techniques.
- For clarity, the table has been divided into groundwater (shallow groundwater and deepest USDW) monitoring techniques and well integrity monitoring (above confining zone). See Table 4-

2 in Appendix A of this document, which is the updated Table 6.

- Please add zinc to the groundwater quality monitoring parameters in Table 7 to complement the monitoring of other commonly occurring heavy metals (Cu, Pb, Cr, Co).
- Zinc (Zn) has been added to the pertinent locations in Table 7 as requested.
- Please analyze the  $d^{13}C$  of the injectate and include it among the injectate testing parameters.
- Comment noted.  $d^{13}C$  has been added to Table 1 of the Testing and Monitoring Plan.
- EPA will require including water density in the ACZ1 monitoring parameters to allow comparisons of water quality monitoring parameters above and below the confining zone and to support understanding of fluid density in the USDW for calculation of the critical pressure.
- Water density sampling as part of a larger fluid sampling protocol has been added to Table 4-2 in Appendix A of this document (the updated original Table 6).
- Please explain the sequence of events regarding data collection (i.e., seismic and water quality evaluations and updated AoR modeling) and the determination of monitoring well placement and depths. It is not clear based on the Testing and Monitoring Plan how CES proposes to collect the data to inform proposed monitoring well placement.
- 3D seismic data will be acquired and incorporated to assist with defining the subsurface. This information will be used to refine and inform the existing AoR model. The placements of the monitor and injection wells will be reviewed and validated based on the updated AoR model prior to drilling the well. As well data are acquired, the AoR model will be updated, and the remaining monitor well placement will be reviewed and updated accordingly.
- CES plans to use shallow groundwater wells (GW1, GW2, GW3, and GW4) sampled on a quarterly baseline schedule. The deeper monitoring well (USDW 1) will be drilled and then sampled quarterly for a 1-year baseline period. These wells are planned on the edges of the CES property. These wells will likely be drilled and sampled before the 3D seismic data are acquired and the injection wells are drilled. CES is investigating to confirm if existing groundwater monitor wells exist on the property that can be used for this purpose.
- Currently, the deeper the  $CO_2$  injection well (INJ 1) and the deeper monitoring wells (OBS 1 and ACZ 1) are located in an optimal location based on the data that are currently available (2D seismic data and the current geological model). The location of the OBS 1 monitoring well is currently planned to be 1100 ft NE of INJ 1. Based on the petrophysical characteristics of the formation, this is a reliable distance, which is designed to observe the breakthrough of  $CO_2$ .
- The 3D seismic survey will help determine the optimal location for the injection (INJ 1) and monitoring wells (OBS 1 and ACZ 1). The 3D seismic survey and inversion results will be used to avoid any potential subsurface complexity such as faults or areas of changing reservoir conditions. This distance of the OBS 1 well may be closer or farther depending on the results of the 3D seismic survey. The geological model, reservoir simulations, and the AoR boundary will be updated at this time.
- After INJ 1, OBS 1, and ACZ 1 are drilled, the data (formation tops, modern well logs, core analysis, updated petrophysical properties, etc.) will be used to update the geological model, reservoir simulations, and the AoR boundary.
- The Testing and Monitoring Plan, on page 17 states that to meet the requirements at 40 CFR 146.95(f)(3)(i), CES will also monitor groundwater quality in the first USDWs immediately

*above and below the injection zone(s). The requirement to monitor USDWs below the injection zone only applies to projects operating under injection depth waivers and does not apply to the CES project. Please edit the sentence accordingly.*

- *Comment noted. The statement in Attachment C on Page 17 has been updated and reads as follows: To meet the requirements at 40 CFR 146.95(f)(3)(i), Clean Energy Systems will also monitor groundwater quality, geochemical changes, and pressure in the first USDWs immediately above the injection zone(s).*
- *Table 6 of the Testing and Monitoring Plan indicates that fluid sampling will be performed in OBS 1; however, Table 7 does not include Panoche sampling for water quality testing. Please clarify whether the sampling proposed to be performed in OBS 1 is for the purpose of groundwater quality monitoring or plume tracking, and update either Table 6 or Table 7 accordingly*
- *Table 4-2 in Appendix A of this paper (original Table 6) has been updated to delineate between groundwater quality monitoring and well integrity monitoring testing scenarios.*
- *The spreadsheet of proposed testing and monitoring activities submitted with the application indicates that continuous DAS monitoring will be performed in INJ1; however, this is not included in Table 6 of the Testing and Monitoring Plan. Please clarify the discrepancy.*
- *Continuous DAS monitoring is currently proposed for INJ-1; however, the injection process will create borehole conditions that are too noisy for meaningful DAS acquisition. If acceptable to the EPA, DAS acquisition in INJ 1 will only occur when the well is shut in, using wireline fiber-optics to record the acoustic (noise) log using DAS, as described in section 7.2.1.6 of the Testing and Monitoring Plan.*
- *Please specify the proposed sampling and recording frequencies for continuous DAS monitoring during the injection phase (i.e., include information similar to Table 3 of the PISC and Site Closure Plan in the Testing and Monitoring Plan).*
- *The sampling (10 seconds) and recording (1 hour) frequencies for continuous DAS monitoring have been added to Table 2 of the Testing and Monitoring Plan.*

***Considerations based on the results of Pre-Operational Testing/Modeling Updates:***

- *If new information or updates to the geochemical modeling based on pre-operational testing raises additional concerns about subsurface geochemical processes (e.g., potential changes in subsurface properties or potential contaminant mobilization), the list of groundwater quality analytical parameters will need to be revisited to make sure that all relevant parameters are represented. In particular, the list of analytes should be compared against comprehensive groundwater chemistry analyses and information on the mineralogy and whole-rock chemistry of the solids in the injection zone and upper confining zone. This comparison will help finalize the groundwater chemistry analyte list.*
- *Comment noted. If subsurface properties change significantly signaling contamination mobilization, groundwater quality analytical parameters will be updated to account for this. Analysis of whole-rock chemistry and mineralogy will be leveraged to update the analyte list appropriately.*
- *CES proposes a 10-year alternative post-injection site care time frame and notes in the PISC and Site Closure Plan (Attachment D) that the post injection site care plan will be finalized based on the results of AoR modeling performed using the data to be collected after pre-operational testing*

*is complete. If, based on the updated modeling, this timeframe is insufficient, the post-injection groundwater monitoring strategy will need to be revised accordingly (e.g., to describe monitoring after year 10 post-injection).*

- *Comment noted. If modeling indicates the existing site care time frame is insufficient, the post-injection groundwater modeling strategy will be updated to accommodate a time appropriate monitoring plan of action.*
- *EPA will need to review construction procedures and specifications for each of the monitoring wells prior to construction; additional information is provided in the well construction and plugging review report.*
- *CES will provide EPA with all relevant construction design, scope, and execution information prior to the commencement of monitoring well construction.*
- *The location of ACZ1 will depend on the final site characterization evaluation and findings about the transmissive nature of any faults based on 3D seismic.*
- *The final location of ACZ 1 depends on subsurface and surface site characterization information included in standard site assessment data sets, including, but not limited to, cultural surface data; 3D seismic data; well log analysis; and structural, facies, petrophysical, and dynamic models.*

## 2.6 CO<sub>2</sub> Plume and Pressure Front Tracking

CES described plans for CO<sub>2</sub> plume and pressure front tracking that include (1) the use of direct methods for tracking the pressure front within the injection zone [40 CFR 146.90(g)(1)] and (2) direct measurements at OBS 1 and indirect geophysical techniques to track the extent of the CO<sub>2</sub> plume [40 CFR 146.90(g)(2)].

### 2.6.1 CO<sub>2</sub> Plume Monitoring

CES proposes direct monitoring of the extent of the CO<sub>2</sub> plume will be accomplished by fluid sampling in the Second Panoche Sand in the Mendota OBS 1 well to the northeast of the injection well to help confirm predictions of CO<sub>2</sub> plume movement. The precise location of this well will be based on where the AoR delineation model predicts detectable pressure change within 6 months and CO<sub>2</sub> saturation of 10 to 20% within approximately one year.

Baseline sampling to monitor the CO<sub>2</sub> plume will be performed during well construction and then once prior to injection. The monitoring frequency during the injection phase will be annual; and during the post-injection phase, monitoring will be annual during years 1 through 3 and in years 5, 7, and 10. However, if CES anticipates CO<sub>2</sub> saturations of 10-20% at OBS 1 within the first year of injection, it would be appropriate to sample more frequently in the first one or two years in case the predictions are an underestimate or overestimate. The analytical parameters are the same as those planned for groundwater quality monitoring above the confining zone, with the additional parameter of water density.

Proposed indirect CO<sub>2</sub> plume monitoring activities include pulsed neutron monitoring, a 3D surface seismic survey or a combination of borehole and surface seismic, and time-lapse vertical seismic profile (VSP) survey:

- Pulsed neutron logging within the Panoche Sands will be performed in OBS 1 and the injection well (Mendota INJ 1) to monitor the formation CO<sub>2</sub>. Following a baseline log in each well, pulsed neutron logging during the injection phase will be quarterly through year 1.5, then annually afterwards; post-injection phase logging will be performed in years 1, 3, 5, 7, and 10.

- Time-lapse VSP surveys will be performed at Mendota OBS 1 to monitor the migration of the plume over an area of about 100 to 2,000 acres. The surveys will be performed during well construction to establish a baseline, and during years 2, 3, and 4 of the injection phase. There will be no VSP monitoring during the post-injection phase.
- Surface 3D seismic surveys will be performed prior to construction to establish a baseline and in year 3 of the injection phase. Post-injection phase 3D seismic surveys will be performed during years 1, 5, and 10 after injection ceases.

The Testing and Monitoring Plan is unclear as to whether time-lapse VSP surveys or 3D surface seismic surveys (or both) are planned. This decision will need to be made prior to issuing the Class VI permit (or at least prior to authorization to inject). If CES only plans to perform time-lapse VSP, this monitoring activity will need to extend into the post-injection phase, and the imaging will need to encompass an area on the larger end of the range CES identifies in order to encompass the entire 2.2 square mile AoR.

## 2.6.2 Pressure Front Monitoring

Proposed direct pressure front monitoring activities include continuous pressure/temperature (P/T) monitoring and distributed temperature sensing (DTS). This monitoring will target the First, Second, and Third Panoche Sands at Mendota OBS 1 and the injection interval at the Mendota INJ 1 injection well. Following baseline measurements, continuous direct pressure front monitoring will occur throughout the injection phase and in Years 1-3 of the post-injection phase. After year 3 post-injection, annual P/T measurements will be taken (with no additional DTS).

Proposed additional pressure front monitoring will be accomplished via continuous passive seismic monitoring to detect seismic events over M1.0 within the AoR. The application states that there will be multiple target locations at a combination of borehole and seismic stations within the AoR but does not identify the specific locations.

### *Questions/Requests for CES:*

- *Table 9 indicates that fluid sampling for CO<sub>2</sub> plume and pressure front tracking will be performed in OBS 1. What parameters does CES propose to analyze?*
- *Please refer to Table 10 for the parameters for fluid sampling.*
- *EPA will require that direct CO<sub>2</sub> monitoring in OBS 1 be performed more frequently than annually in the initial years of injection (i.e., through year 2) to validate modeled predictions of CO<sub>2</sub> plume movement.*
- *OBS 1 will be monitored on a quarterly basis during the first 1.5 years of injection. After the first 1.5 years, the sampling rate will be annual.*

Changed to quarterly monitoring for Years 0-1.5 and Annually from Years 1.5 and on

- *The spreadsheet of testing and monitoring activities identifies injection profile monitoring (Spinner) surveys in INJ 1 and CO<sub>2</sub> analysis as direct CO<sub>2</sub> plume monitoring activities and monitoring of injection volume in INJ 1 as a pressure front monitoring technique; however, these do not appear to be plume and pressure front monitoring techniques. Please remove them from the testing and monitoring strategy or clarify how they will be used to track the CO<sub>2</sub> plume and pressure front in the subsurface.*
- *A spinner survey (or production logging tool) is commonly used during the injection to identify*

*the flow rates (or fractional rates) of specified perforation intervals. This information provides valuable results in helping to explain/monitor well behavior during the test analysis and in the subsequent simulation efforts (model calibration) for plume and pressure prediction, which will be critical to the monitoring and validation.*

- *Table 9 indicates that VSP in OBS 1 will be performed in Years 2, 3, and 4 of the injection phase. EPA will require that additional VSP be performed in the later years of the injection phase to provide additional data points for the non-endangerment demonstration.*
- *Comment noted. As the site-specific data are acquired and the pressure and plume AoRs are updated subsequently, reevaluation of VSP acquisition will be reviewed after Year 4.*
- *Please clarify how the VSP and 3D seismic will work together to provide plume tracking (taking into account the capabilities and strengths of each method). In particular, it is important that each test is employed at a consistent frequency throughout the injection and post-injection phases to allow data comparisons to support the non-endangerment demonstration.*
- *The proposed seismic methodology will be to first acquire a surface seismic 3D survey to image the horizons and faults in the study area. Modeling for the 3D VSP will then be performed to assess the impedance contrasts expected downhole and coverage map for the 3D VSP. If it is determined through modeling that the plume can be imaged with 3D VSP, then 3D VSP will be the proposed seismic method for mapping the plume post-injection, with approval from EPA.*
- *What is the planned resolution and extent of the 3D seismic surveys?*
- *The current design of the 3D seismic survey will cover the extents of the plume at 100 years at full fold and full azimuth (as allowed by infrastructure constraints). The inline and crossline bin spacing will be less than 100 ft, to ensure that faults and reflecting horizons are properly imaged.*
- *There are numerous inconsistencies between the tables in Attachments C and E and the spreadsheet of testing and monitoring activities (e.g., in the frequencies at which various testing and monitoring activities are to be performed). Please revise the spreadsheet or the plans as needed or resolve the discrepancies.*
- *Tables in Attachment C and E will be updated accordingly.*
- *Please describe the proposed passive seismic monitoring network (i.e., the number and location of monitoring stations). Are any state or federally operated (e.g., USGS) seismic monitoring stations nearby that will inform seismic monitoring of the CES project?*
- *An induced seismicity monitoring (ISM) surface geophone network and a distributed acoustic sensing (DAS) fiber-optic cable will be installed permanently downhole in monitoring wells OBS 1 and ACZ 1 and will be used to locate microseismic events with accuracy in real time. As a part of standard operating procedure, these data will also be integrated with information from nearby state and federally operated seismic monitoring stations to provide a safety net. The combined high-order governmental, surface ISM, and downhole DAS passive seismic monitoring network will quickly and accurately locate seismic events of interest in and around the AoR. Currently, there are governmental seismic monitoring stations but they are more than 10 miles away from the Mendota site and thus would provide only limited information.*
- *The spreadsheet of testing and monitoring activities indicates that continuous DTS monitoring will be performed for pressure front tracking in **OBS 1** for the first 3 years of the post-injection site care timeframe, but this is not included in Table 6 of the PISC and Site Closure Plan. Please clarify the discrepancy.*

- *OBS 1 was added to the DTS row of Error! Reference source not found. of the PISC and Site Closure Plan.*
- *Please also explain why additional DTS monitoring is not proposed beyond year 3 post-injection, or what data trends may indicate that additional temperature monitoring is not warranted, particularly in consideration of collecting post-injection phase data to support the non-endangerment demonstration.*
- *DTS monitoring has been changed to 10-year monitoring, in line with the pulsed neutron logging plan. DTS monitoring subsurface equipment will still be in place once the initial post-injection time is completed and thus may continue to be monitored if so required.*

***Considerations based on the results of Pre-Operational Testing/Modeling Updates:***

- *Updated modeling (numerical multiphase transport modeling and geochemical modeling) to demonstrate the adequacy of the proposed 10-year alternative post injection site care time frame will be conducted in the pre-operational testing phase. If this timeframe is insufficient based on the updated modeling, the post-injection plume and pressure front tracking strategy will need to be revised accordingly.*
- *As the modeling work is updated with the site-specific data, the 10-year alternative post-injection site-care timeframe will be reevaluated and modified if needed. The post-injection plume and pressure front tracking strategy will be updated according to the revised modeling results.*
- *The maps in the application on which monitoring locations are overlain (e.g., Figures 3 through 7 of the Testing and Monitoring Plan) are based on the pre-construction AoR modeling results; any changes to the predicted position of the CO<sub>2</sub> plume and pressure front based on the AoR modeling evaluation may necessitate reexamination of the well locations and revision of these maps and cross sections.*
- *As the site-specific data are acquired and the pressure and plume AoRs are updated subsequently, reevaluation of the well locations will be done according to the changes in the pressure and plume front.*
- *Mendota OBS 1 is currently described as targeting the Second Panoche Sand; if the Fourth Panoche (the alternate injection zone) is selected, this monitoring well should penetrate and be screened in that sand. Likewise, pressure/temperature monitoring in that zone would be necessary as well.*
- *Current strategies target the Second Panoche Sandstone as the primary target and the First Panoche Sandstone stratigraphically above it as the secondary target. If the primary and secondary targets prove untenable, then the Mendota OBS 1 well would be extended through the Third Panoche and the Fourth Panoche, which comprise the tertiary CO<sub>2</sub> injection zone option. Using the Fourth Panoche as an injection interval is unlikely at this time.*
- *CES will need to clarify which seismic methods will be used (i.e., VSP and/or surface seismic survey) prior to authorization of injection. If only VSP is planned, the imaging area will need to be at a range closer to the high end of the range (i.e., 2,000 acres) to encompass the entire AoR.*
- *The proposed seismic methodology will be to first acquire a surface seismic 3D survey to image the horizons and faults in the study area. Modeling for the 3D VSP will then be performed to assess the impedance contrasts expected downhole and coverage map for the 3D VSP. If it is determined through modeling that the plume can be imaged with 3D VSP, then 3D VSP will be the proposed seismic method for mapping the plume post-injection, with approval from EPA.*

- *The QASP may need to be updated when final determinations are made based on pre-operational testing about specific testing and monitoring activities (e.g., related to plume and pressure front tracking)*
- *The QASP will be updated accordingly based upon pre-operational testing and monitoring activities.*

## 2.7 Air/Soil or Other Testing and Monitoring

Based on the currently available information about the geologic setting (i.e., the depth of the injection formations and the lack of evidence for the presence of transmissive faults or fractures), surface air and/or soil gas monitoring are not needed to detect movement of fluid that could endanger USDWs within the AoR.

### *Considerations based on the results of Pre-Operational Testing/Modeling Updates:*

- *If, based on the results of planned pre-operational testing, uncertainties about the geologic setting are identified, the need for air and/or soil gas monitoring or other monitoring will be reconsidered.*
- *Air and/or soil gas monitoring will be reviewed based upon the results of the pre-operational testing and confirmation of geological uncertainties.*

## 2.8 Quality Assurance Procedures

EPA evaluated the Quality Assurance Surveillance Plan (QASP) submitted with the permit application to verify that all of the testing activities, analytes, etc., included in the QASP are consistent with planned injection and post-injection phase testing and monitoring. The QASP described sampling methods; sample handling and custody; analytical methods; quality control; instrument/equipment testing, inspection, and maintenance; data management, e.g., recordkeeping and tracking practices; and data review, verification, and validation procedures.

Most monitoring activities listed in Attachment C: Testing and Monitoring Plan were addressed in the QASP. The exceptions are two MITs: temperature logging and oxygen activation (OA) logging. The procedures for these MITs should be described in the QASP as they are not sufficiently detailed and described in the Testing & Monitoring Plan.

All of the monitoring activities listed in Attachment E: Post-Injection Site Care and Site Closure Plan were addressed in the QASP.

### *Questions/Requests for CES:*

- *For completeness, please revise the QASP to include the details of the temperature and oxygen activation procedures to demonstrate external MI (including specific calibration procedures for OA logging).*
- *CES will develop specific procedures for each well after drilling and logging are completed. For each individual well with temperature and OA logging, there will be specific requirements and instructions for pre- and post-calibrations, normalizations, and interpretations of MI that take core, open- and cased-hole logs, and any other vital information into consideration. These specific procedures allow the operations to be tailored to include exact depths, intervals, casing sizes, wellbore fluids, and environmental aspects, which allow for the best MI analysis possible.*

### **3 Enclosure 2 – Evaluation of Planned Construction and Plugging Procedures at the CES-Mendota Class VI Site**

This well construction and plugging evaluation report for the proposed Clean Energy Systems (CES)- Mendota Class VI geologic sequestration (GS) project summarizes EPA's evaluation of several related activities associated with constructing and plugging the injection well and monitoring wells associated with the planned GS project and corrective action in the area of review. Due to the similarities of these activities, they are evaluated in a single report. These activities are described in Attachments B, D, E, and G of the permit application. This review also identifies preliminary questions for CES

#### **3.1 Injection Well Construction**

Section 5 of the permit application narrative and Attachment G describe the proposed injection well construction design. The proposed injection well design is presented in Figure 1 of Attachment G and Figure 51 of the narrative. The figure shows the position of the various casing, tubing and perforations to be implemented in the Mendota\_INJ\_1 injection well.

The proposed injection well will be a new vertical well, to be drilled with a deviation of less than 5 degrees. The application explains that well logs to provide formation properties and any needed formation sampling will be run from 7,432 feet to 1,800 feet (see additional evaluation under "Pre-Operational Testing of the Injection Well," below). If, based on cement and casing evaluation logs, a competent formation to set casing is found above the Third Panoche Shale, then the 9-5/8 inch hole may not be drilled to 10,412 feet. A 7 inch, 38 lb/ft, L-80 casing from 0 to 7,332 feet and then 7 inch 38 lb/ft L-80 13Cr casing from 7,332 feet to 10,412 feet will be run into the hole and cemented to surface. After the cased hole logs are run, the well will be perforated and completed with an injection packer and 3-1/2 inch L-80 13Cr tubing string. The perforation interval will be selected based on the log analysis, but is anticipated to be from about 9,600 feet to 9,820 feet.

Well construction will provide 3 casing barriers with generously cemented annuluses covering the USDW from the surface to 1,800 feet. Covering the USDW will be the 16 inch, 10-% inch, and 7 inch casings.

A removable 3-% inch tubing string with a retrievable seal bore packer will be used to facilitate movement and changeout of the tubing string and allow for needed testing. The tubing string will be fitted with nipple profiles to facilitate testing of the tubing, packers, and tubing annulus. Pressure and temperature monitors will be installed downhole and at surface on the various annular ports for the casing wellhead and tubing.

All casings will be cemented to surface. The application states that there are currently no known conditions preventing bringing cement to surface without a stage collar on the surface, intermediate, and long strings. Coverage of the annulus and cement strength will be evaluated with wireline cement bond log (CBL) and ultra-sonic cement evaluation logs.

The conductor casing is expected to be driven but a provision has been allowed to drill a hole and cement the casing if soil conditions do not permit driving the casing to <sup>86</sup> feet.

The surface casing will cover the USDW at a maximum depth of 1,615 feet TVD. Surface casing depth is expected to be 1,800 feet. Type II/V cement meets ASTM Specification C 150. It is a low alkali Portland cement for general use and where high sulfate resistance is required.

The intermediate casing will be set 100 feet into the top of the Moreno Shale confining zone. Cement will be brought back to surface from 7,432 feet TVD. Class G cement is an API grade cement with specifications defined in various API standards, primarily API Spec 10A. Pozzolan will be an additive to reinforce the cement slurry.

The long casing string will be set 100 feet into the Third Panoche Shale but may be set higher if an appropriate formation can be found. Cement will be brought back to surface from 10,412 feet TVD without a need for staging equipment. The CO<sub>2</sub> resistant EverCRETE\* will be taken to above the Moreno Shale with a top of 7,332 feet to 7,000 feet. The application describes EverCRETE\* as state of the art for storage of CO<sub>2</sub> for GS and enhanced oil recovery projects that can be incorporated into standard primary cementing operations for zonal isolation of new CO<sub>2</sub> injection wells.

*Comments on Well Construction Procedures and Materials*

The Class VI Rule requires that well component materials be compatible with the planned injectate and formation fluids that may be encountered and can resist corrosion for the duration of the project. The application states that materials suitable for CO<sub>2</sub> environment are clearly specified in API, ANSI/NACE and ASTM standards and that suppliers of components will be required to demonstrate and provide certification that their equipment has been tested and evaluated against these standards and that they are suitable for purpose in the environment defined.

While a preliminary injectate composition is described in the narrative, the application also states that well construction materials will be reviewed following tests of the composition, properties and corrosiveness of the injectate. When CES provides details about the specific materials, EPA will conduct a fuller evaluation. However, based on the impurities anticipated to be in the CO<sub>2</sub> injectate, as listed in Table 8 of the narrative (i.e., H<sub>2</sub>O, O<sub>2</sub>, H<sub>2</sub>, N<sub>2</sub>, CO, Ar, NO, NO<sub>2</sub>, H<sub>2</sub>S, and NH<sub>3</sub>), CES's proposed approach to construction appears to be acceptable.

The strength of all proposed well materials must be capable of resisting all of the forces encountered. The application states that casing selection has been evaluated against industry standard worst-case loads to determine if selected casing sizes, material thickness and grade are suitable for the environment in terms of pressure and temperature. Where applicable, special loads were created to determine if the casing could handle a load not covered by current standards. Areas evaluated are casing/tubing burst, collapse, axial and compressive strengths in unilateral, bilateral and triaxial (Von Mises) load scenarios.

Tables 10 to 14 in the application narrative provide casing design specifications and details. There are inconsistencies between the text and the casing details in Tables 13 and 14 regarding the casing grade to be used in the surface, intermediate, and long string casings. The text states the grades as L-80 for the intermediate casing and long string casing but T-95 in the two tables. The grades listed in Tables 13 and 14 are also inconsistent for the surface and intermediate casing strings.

- \* Please refer Table 4-3 in Appendix A of this document which updates Table 14 below for the correct material types for the surface and intermediate strings.

Table 13: Mendota INJ 1 casing specifications

Name	Depth Interval (feet)	Outside Diameter (inches)	Inside Diameter (inches)	Weight (lb/ft)	Grade (API)	Design Coupling (Short or Long Threaded)	Thermal Conductivity @ 77°F (BTU/ft hr, °F)	Burst Strength (psi)	Collapse Strength (psi)
Conductor	86	22	21	197.41	B	Welded	26.13	2440	1950
Surface	1800	16	15.01	84	N80	Long	26.13	4330	1480
Intermediate	7432	10.75	9.760	55.5	N80	Long	26.13	6450	4020
Long-string	7332	7	5.920	38	T-95 Type 1	Long	26.13	12830	13430
Long-string	10412	7	5.920	38	TN 95Cr13	Long	14.92	12830	13430

Table 14: Mendota INJ 1 casing details.

Casing String	Casing Depth	Borehole Diameter	Wall Thickness	External Diameter	Casing Material	String Weight
Conductor	86 ft	26 in	1 in	22 in	197.41ppf Grade: B Connection: Welded	16997 lbs
Surface	1800 ft	20 in	0.875in	16 in	84 ppf Grade: Connection: Tenaris ER	151200 lbs
Intermediate String	7432 ft	14.75 in	0.495 in	10.75 in	55.5 ppf Grade: Connection: Tenaris Blue	412476 lbs
Long String	7332	9.625 in	0.590 in	7.0 in	38 ppf Grade: T-95 Type1 Connection: Tenaris Blue	422792 lbs
	10412	9.625 in	0.590 in	7.0 in	38 ppf Grade:T95-13Cr Connection: Tenaris Blue	

The injection well construction procedures and materials are satisfactory except as discussed and noted below.

#### *Comments on Cementing*

The proposed cementing procedures must provide a continuous sheath of cement from the bottom of each casing string to the surface with placement of the surface casing below the depth of the lowermost USDW. The application states that all three casing strings will be cemented from total depth to the surface and will provide three casing barriers with cemented annulus covering the USDW from surface to 1,800 feet. As noted in the geologic evaluation report, formation sampling will be performed to confirm the

depth of the lowermost USDW; however, a surface casing depth of 1,800 feet is likely to be adequate.

CO<sub>2</sub> resistant EverCRETE cement will be placed from the total depth of the wellbore through the Panoche Formation to above the Moreno Shale. The EverCRETE\* system should provide zonal isolation during injection, throughout the life of the well, and after plugging. CES states that it has proved to be highly resistant to CO<sub>2</sub> attack in the most extreme laboratory conditions, including environments with wet supercritical CO<sub>2</sub> and CO<sub>2</sub> water saturation in downhole conditions. As with the well construction materials described above, a definitive determination of the proposed cementing plan is pending final analysis of the injectate; however, based on the anticipated impurities in the CO<sub>2</sub> stream, CES's proposed cementing approach appears to be acceptable.

**Questions/Requests for CES:**

- *Please clarify the casing grade for the surface, intermediate, and long string casings in the text and in Tables 13 and 14.*
- *Please refer to Table 4-3 in Appendix A, which is the updated Table 14.*
- *Please provide data from the manufacturer that demonstrates EverCRETE is more protective than Portland Cement under the deep well conditions of CO<sub>2</sub> attack. How long will EverCRETE endure under long term CO<sub>2</sub> corrosive conditions, and what data support these conclusions?*
- *Barlet-Gouedard et al. (2006) describe how the EverCrete system is different from and superior to conventional Portland cements (Barlet-Gouedard, V., Rimmelé, G., Goffe, B., and Porcherie, O. 2006. Mitigation Strategies for the Risk of CO<sub>2</sub> Migration Through Wellbores. SPE-989284-MS. <https://doi.org/10.2118/98924-MS>).*
- *Are capillary tubes used for installation of either fiber optics or other equipment external to the casing? If so, what is their internal diameter, and how will they be plugged at the end of the well's life?*
- *Cables are used for both fiber optics and gauges, though they are not technically capillary (hydraulic) lines; however, if they were to get compromised, it is possible to have a leak path to surface. This is mitigated with a wellhead outlet. At the end of the well's life, a plug can be put on the end of the cable. Cables will be pulled with tubing at end of life.*

**Considerations based on the results of Pre-Operational Testing/Modeling Updates:**

- *CES will need to demonstrate that the selected well component materials are compatible with formation fluids that may be encountered, as described in the results of pre-injection formation testing, and that they can resist corrosion for the duration of the project*
- *Comment noted. CES does not expect any changes as per current information on fluids to be encountered. With low chlorides and no H<sub>2</sub>S, the fluids should be easily handled by current materials prescribed.*
- *The surface casing depth/cementing specifications may need to be modified based on the results of analyses of sampled formation water during drilling of the injection and monitoring wells to determine the base of the lowermost USDW.*
- *Noted: As new information is collected about the USDW, casing depth/cementing specifications will be adjusted.*
- *Following the pre-construction measurement of the composition, properties, and corrosiveness of*

*the injectate, the well construction materials and cement will need to be reviewed based on the results of these tests.*

- Noted: As plant facilities are designed and adjustments are made to the output CO<sub>2</sub> stream, the well construction materials will be reviewed and corrected for appropriateness to meet design standards.*
- The final construction schematics should reflect CES's decision to inject into the Second Panoche (the primary injection target) or the Fourth Panoche (the alternate injection zone).*
- Injection into the Fourth Panoche is unlikely and not currently being planned for. If the Fourth Panoche becomes a target, the final construction schematics will be updated and provided after a site-specific data are collected.*

### 3.2 Safety Valves and Shut-Off Devices

The wellhead will be equipped with safety valves and shut-off devices at the injection system and annulus of the well. Automatic shutdown devices would be activated under certain conditions, including when wellhead pressure exceeds the specified shutdown pressure and/or the annulus pressure indicates a loss of external or internal well containment.

The Emergency and Remedial Response Plan, described in Attachment F and Section 4.0 of the application, provides a description of the events that may necessitate gradual or immediate shutdown of the well depending on the severity of the event. Attachment A describes the shutdown procedures.

#### *Questions/Requests for CES:*

- Please provide additional information about the types of safety valves and shut-off devices that CES proposes to use; in particular, please describe how they will be linked to the continuous injection and annulus monitoring system.*
- There are currently two options for safety valves that are being evaluated. The first is a subsurface safety valve. This valve is typically mechanical (hydraulic and electrical options available) in operation as it allows fluid to flow during injection phase but will close during cessation of fluid flow not allowing downhole fluids or pressures to come to surface. The subsurface safety valve will potentially create excessive downtime as it is in the flow stream and will need to be maintained periodically to maintain functionality. The subsurface safety valve will impede wireline operations because it must be removed before wireline operations can be done. Another option currently thought to be better is to provide pneumatically driven hydraulically actuated gate valves in line with the injection stream in the wellhead. These units can be connected to control systems to drive the opening and closing of the valves based on feeds from downhole signals with respect to temperature and pressure. It is at the surface, so maintenance and replacement are easier and there are more options for corrosion-resistant inlays. It will not interfere with any downhole operations such as wireline logging. Examples of the valves and operation equipment can be provided upon request.*
- Please revise the injection well schematics to show the surface and downhole pressure and temperature gauges that are referenced in the Testing and Monitoring Plan.*
- Injection and monitoring wells schematics have been modified and updated with gauge references. Please refer to Appendix B in this document.*

### 3.3 Pre-Operational Testing of the Injection Well

The proposed pre-operational formation and well testing program required at 40 CFR 146.82(a)(8) and 146.87 is described at Section 6 of in the permit application narrative and in Attachment G. Attachment G describes tests and logs to be performed: at the surface, in the surface section of wellbore, the intermediate section of wellbore, and the total depth section of wellbore, along with tests to be performed during and after casing installation (i.e., cement evaluation and mechanical integrity, formation CO<sub>2</sub> saturation testing, and formation testing). The proposed testing and logging program is considered comprehensive and acceptable, except as noted below.

#### *Questions/Requests for CES:*

- *Please add caliper logs to the logging program before surface, intermediate, and long string casing are installed, in accordance with 40 CFR 146.87.*
- *A caliper log was added to the logging programs for all runs.*
- *Please add temperature logging after each casing string is set and cemented in accordance with 40 CFR 146.87.*
- *Temperature logs were added to the cement evaluation program. Multifinger caliper was also added for the mechanical inspection for all casing runs.*

#### *Considerations based on the results of Pre-Operational Testing/Modeling Updates:*

- *As described in other reports (e.g., the AoR modeling evaluation and the testing and monitoring evaluation reports), the proposed formation testing program will provide information to support the setting of operating conditions of the permit, provide inputs for modeling to delineate the final AoR, and establish a baseline for parameters that will be measured during injection and post injection phases. As needed, these considerations may be revised as the reviews proceed to ensure that the pre-operational testing and logging program will collect the information needed to verify the well is properly constructed; gather information on subsurface formations and fluid geochemistry; and address all identified uncertainties.*
- *As more information is gathered, models, programs, and procedures will continue to be updated and reviewed to make sure all identified uncertainties are addressed.*

#### **3.3.1 Pressure Falloff Testing (PFOT)**

##### General Comments

The proposed falloff test procedures presented in Attachment G are duplicated in Attachment C (the Testing and Monitoring Plan), but with minor differences between the two attachments. The differences were noted in step 18 of the Falloff Test Report Requirements and in a missing step 2 in the Evaluation of the Test Results in Attachment C that is present in Attachment G. Also, the steps in Attachment C should be re-numbered for consistency with Attachment G. In addition, steps 3, 4, and 5 in the Pretest Planning section of Attachment C are inconsistent with steps 3 and 4 in Attachment G and the reference to an appendix concerning pressure gauges is missing in Attachment C. The referenced appendix is included in the Region 9 PFOT Guidelines document.

#### *Questions/Requests for CES:*

- *Please address the discrepancies between Attachments C and G discussed above and provide a complete and correct copy of the proposed pressure fall-off test procedures and a copy of the referenced Appendix.*
- *Appendix C in this document resolves any differences and gives the updated falloff test procedures according to the comments and suggestions.*
- *Please also include this in the Testing and Monitoring Plan.*
- *Please refer to Appendix in this document for the updated falloff test procedures.*

The proposed PFOT procedures in Section 8 of Attachments C and G are nearly identical to the Region 9 PFOT Guidelines document, except as noted below:

### 3.3.2 Timing and of Fall-off Testing and Report Submission

The initial PFOT should be performed upon well completion, but before injection operations begin and annually thereafter, as described in 40 CFR 143.87(e)(1) and the PFOT Guidelines. See additional discussion of the PFOT timing in the testing and monitoring evaluation report.

### 3.3.3 Fall-off Test Report Requirements

#### *Questions/Requests for CES:*

Please add “elapsed time ” to the end of the first bullet of Step 18 in Attachment C.

- *Comment noted. Please see Appendix in this document for the updated falloff test procedures.*

#### **Planning**

The ninth bullet is not included in the Region 9 PFOT Guidelines. The testing options described would be subject to EPA approval.

#### *Questions/Requests for CES:*

- *Please add that the testing options for use of other pressure transient tests described in the ninth bullet under “Planning” are subject to EPA approval.*
- *Comment noted. The following statement has been added at the end of the ninth bullet (refer to Appendix in this document): “However, other pressure transient tests will be subject to EPA approval prior to the application.”*

### 3.3.4 Pretest Planning

Step 3: Bottomhole pressure measurements are not only superior to surface pressure measurements but are required in all pressure transient tests unless measurement of only surface pressures is approved in advance by EPA. The second sentence is also not applicable to PFOTs unless approved by EPA.

Step 4: This language was added by CES and is acceptable.

Step 5: This is identical to Step 4 in the Region 9 PFOT Guidelines except for omission of the reference to the Appendix in the Guidelines. This step is included in Attachment C, but not in Attachment G; as noted above, EPA requests that the two attachments be consistent.

*Questions/Requests for CES:*

- Please revise Step 3 under “Pretest Planning” to require bottomhole pressure in addition to surface pressure gauges for conducting PFOTs performed without advance EPA approval for use of only surface pressure gauges.
- *Comment noted. Step 3 has been replaced by “Bottomhole pressure measurements are required.” Please refer to Appendix in this document for the updated test procedures.*

### **3.3.5 Conducting the Fall-off Test**

Steps 6 through 11 are not included in the Region 9 PFOT Guidelines and were added by CES. They are acceptable with the following exception in Step 9: the maximum injection pressure should not exceed the maximum allowable surface injection pressure specified in the permit, which will be limited based on the formation fracture pressure and a safety factor.

*Questions/Requests for CES:*

- *Please revise Step 9 under “Conducting the Fall-off Test” to state that the injection pressure will not exceed the maximum allowable surface injection pressure specified in the permit.*
- *Comment noted. In Step 9, “but not exceeding the daily injection volume limit of the UIC Permit” was replaced by “but the injection pressure will not exceed the maximum allowable surface injection pressure specified in the permit.” See Appendix C in this document.*

### **3.3.6 Evaluation of Test Results**

Step 2 in Attachment G is missing in the PFOT procedures in Attachment C but is not included in the Region 9 PFOT Guidelines. It is an acceptable addition to the procedure, but the Attachment C and G PFOT procedures should be consistent.

Step 3 in Attachment C (Step 4 in Attachment G), fourth bullet in the Attachment C version of the FOT procedure omits the phrase “and skin pressure drop” that is included in the PFOT procedure in Attachment G.

Step 5 in Attachment C (Step 6 in Attachment G) is not included in the PFOT Guidelines but is an acceptable addition to the PFOT procedure.

The language added by CES that follows Step 5 in Attachment C (Step 6 in Attachment G) is acceptable, but the second paragraph referring to “unusual petition approval conditions” is not applicable to Class VI wells. Likewise, the discussion of comparisons of PFOT results to no-migration petition data is not applicable to Class VI permits. However, this information may be relevant to AoR reevaluations.

*Questions/Requests for CES:*

- *Please add Step 2 to the FOT procedure in Attachment C.*
- *Please refer to Appendix in this document for the updated falloff testing procedures.*
- *Please add the language referring to skin pressure to the FOT procedure in Attachment C for consistency with the language in Step 4 in Attachment G.*
- *Please refer to Appendix C in this document for the updated falloff testing procedures.*
- *Consider revising the discussion in the second paragraph to discuss how unanticipated FOT*

*results might inform AoR reevaluations.*

- *Comment noted. The second paragraph after Step 6 and the discussion of comparisons of PFOT results to no-migration petition data have been removed. Please refer to Appendix in this document for the updated falloff testing procedures.*

### 3.4 Monitoring Well Construction

EPA recommends in Class VI guidance that monitoring well construction be reviewed in a manner that is similar to the injection well review (especially for the deep ground water monitoring wells).

CES describes seven proposed monitoring wells in the Testing and Monitoring Plan and indicates that the location and design will be finalized in a later phase of the project. EPA requests that CES provide construction procedures and specifications for each well (particularly ACZ\_1 and OBS\_1) for EPA to review in the context of updated geologic information.

Note that EPA understands that the California Regional Water Quality Control Board will need to approve the construction of any new monitoring wells. While this will not be a UIC permit condition, it is relevant to CES's planning of its monitoring well network and is being shared for informational purposes.

#### *Questions/Requests for CES:*

- *Please propose construction procedures and specifications for the proposed monitoring wells. While EPA understands that final locations and depths of the monitoring wells are pending, any available information about the casing, cement, and devices that will be used to sample fluids and measure temperature, pressure, etc., that are described in the Testing and Monitoring Plan is requested.*
- *Detailed well schematics for the monitoring wells and tables along with plugging diagrams have been provided in Appendix B in this document.*

#### *Considerations based on the results of Pre-Operational Testing/Modeling Updates:*

- *The monitoring well construction details and locations will need to be reviewed and modified as necessary based on updated geologic information collected during drilling of the injection well and planned pre-operational seismic surveys.*
- *Comment noted. Seismic surveys and initial drilling related to subsurface geologic information will be integrated into the geologic models, which will, in turn, be used to optimize monitoring well location and construction decisions. CES will take every opportunity to maximize the efficacy of subsurface model generation and management to optimize field-based drilling and monitoring activity.*

### 3.5 Injection Well Plugging Plan

The CES injection well plugging plan in Attachment D of the application describes planned tests or measures to determine bottom-hole reservoir pressure and planned internal and external mechanical integrity tests. The MITs are listed in Table 1, and include an acoustic survey and temperature log, as required by 40 CFR 146.92. It also provides information on plugs (with materials and methods noted in

Table 2), and a narrative description of plugging procedures. The Post Plug and Abandonment Well Diagram is provided in Figure 6.4.

Table 2 of Attachment D (reproduced below) presents the plugging details.

Plug Information	Plug #1	Plug #2	Plug #3	Plug #4
Diameter of boring in which plug will be placed (in.)	5.92	5.92	5.92	5.92
Depth to bottom of tubing or drill pipe (ft)	9637	7782	1950	100
Sacks of cement to be used (each plug)	145	51	51	20
Slurry volume to be pumped (bbl)	30	11	11	4
Slurry weight (lb./gal)	15.8	15.8	15.8	15.8
Calculated top of plug (ft)	8837	7382	1650	0
Bottom of plug (ft)	9637	7532	1950	100
Type of cement or other material	CO <sub>2</sub> Resistant	Class G	Class G	Class G
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced	Balanced	Balanced	Balanced

The bottom-most plug (the only one that is anticipated to come into contact with the CO<sub>2</sub> injectate after injection operations cease) is to be composed of CO<sub>2</sub>-resistant cement, and the remaining plugs will be Class G cement. It is not clear why CES is not proposing to use the same EverCRETE product that is proposed in well construction to plug the injection well. If, based on their responses to EPA's questions about EverCRETE, this system is approved, it may be appropriate to use the same product when plugging the injection well.

- There are many CO<sub>2</sub>-resistant cement formulations. The EverCRETE cement was chosen specifically for the injection casing due to the thin annulus between the open hole and the outer diameter of the casing. There are, however, other suitable options for cementing the casing. The self-healing properties of the EverCRETE system enable the cement to endure during the stress of the injection process during the life of the well. Cement plugs are not subject to these types of stresses and as such do not require such a high-grade cement formulation.*

The plugging procedures state that the test pressure should be maintained +/- 10% for 30 minutes in order to pass the test (page 8). The well test pressure during the plugging procedure should not change more than 5 percent in 30 minutes.

- The plugging procedures will be updated to change "the test pressure should be maintained ± 10% for 30 minutes in order to pass the test (page 8)." to "The well test pressure during the plugging procedure should not change more than ±5% in 30 minutes."*

The Injection Well Plugging Plan is subject to revisions to reflect the actual depths of the Moreno and Panoche Formations, selection of the injection zone, and determination of the base of USDWs and final well construction details, based on geophysical logs and interpretation of site geology after the injection well is drilled. Estimated depths of the Moreno and Panoche Formations, injection zone, USDW base, and significant water and hydrocarbon bearing zones encountered should be included in the well plugging schematic.

The cement plug at the base of the intermediate casing is misplaced on the plugging diagram and in Table 2. It should be placed at 7,582 to 7,382 feet instead of 7,782 to 7,582 feet. The surface plug appears to be placed from +/-10 feet to the surface but is described as from 100 to 0 feet in the plugging diagram and in Table 2.

According to Figure 6.4, the perforations are 9,337 - 9,537 ft and the bridge plug is proposed to be set at

9,637 ft. This would mean that the bridge plug would be set below the injection perforations, followed by balancing a Class G cement plug across those perforations. EPA recommends the following changes to provide a solid block of CO<sub>2</sub>-resistant cement covering the injection perforations and have the benefit of a cement retainer on top of the block with another plug on top of that:

1. Set bridge plug at 9,637'.
  2. Set cement retainer at 9,237'.
  3. Pump CO<sub>2</sub>-resistant cement through cement retainer under pressure (to squeeze some cement into the perforations). Use enough cement to fill the ~400' of 7" casing between the bridge plug and the cement retainer.
  4. String out of cement retainer and balance 100' - 200' of CO<sub>2</sub> resistant cement atop the cement retainer.
- *Due to the need to have cement 100 ft below perforations per California regulations, it is preferable not to use the retainer to squeeze. To ensure cement is below the perforations, extra operations will be required (i.e., bailer) to fill the gap between the bottom of the perforations and the bridge plug. Using the configuration prescribed above will not allow mud below perforations to be displaced. In addition, there needs to be 500 ft of cement above the top of the perforations, as per California requirements. It is likely that two batches of 400-ft cement plugs will be needed. The plug procedure will be modified to accommodate both requirements.*
    1. Set bridge plug at 9,637 ft.
    2. Pump CO<sub>2</sub>-resistant cement to 9237 ft.
    3. Circulate and two stands above 9237 ft.
    4. Shut in well and pressure well to 500 psi for 30 minutes to squeeze cement into perforations. This is typically called a hesitation squeeze.
    5. Move pipe to top of cement (9237 ft) and commence cement operations with CO<sub>2</sub>-resistant cement to achieve cement to 8837 ft depth.

#### **Questions/Requests for CES:**

- *Please revise the plugging procedure to state that the test pressures should be maintained at +/-5 % for 30 minutes.*
- *The plugging procedures have been updated accordingly.*
- *Please add the estimated depths of the Moreno and Panoche Formations, the selected injection zone, the base of the lowest USDW, and significant water and hydrocarbon saturated zones encountered in the wellbore to the well plugging schematic.*
- *Comment noted. CES does not anticipate entering zones of significant water or hydrocarbon saturation at the planned well plug sites. Figure 5-1 of Appendix B illustrates the Moreno and Panoche formations as well as the primary injection zone relative to the well plugging schematic.*
- *Please correct or clarify the depths of the cement plugs at the intermediate casing shoe and the base of the conductor pipe to the surface in the plugging diagram and in Table 2.*
- *The depth of the cement plugs has been corrected. The diagram was changed for the conductor to reflect the cement plug covering the 22-in. shoe and to surface.*
- *Please revise the depth and procedures associated with the bridge plug at the bottom of the well*

*as described above.*

- *The depth and procedures associated with the bridge plug has been updated.*
- *Please explain why CES plans to use different cement to plug the well than the one proposed for use in construction.*
- *There are many CO<sub>2</sub>-resistant cement formulations. The EverCRETE cement was chosen specifically for the injection casing due to the thin annulus between the open hole and the outer diameter of the casing. The healing properties of the EverCRETE system enable the cement will endure during the stress of the injection process during the life of the well. Cement plugs are not subject to these types of stresses and as such do not require such a high-grade cement formulation. For those plugs that are not in contact with CO<sub>2</sub> then conventional Class G cement is considered appropriate*

***Considerations based on the results of Pre-Operational Testing/Modeling Updates:***

- *The Injection Well Plugging Plan and well schematic will need to be revised to represent actual depths of the Moreno and Panoche Formations, the selected injection zone, and the base of the lowest USDW based on geophysical logs and modified interpretation of site geology after the injection well is drilled and completed.*
- *Comment noted. Well schematics will be revised once the well is drilled and formation tops accurately identified.*
- *The final well plugging schematics will need to reflect CES's decision to inject into the Second Panoche (the primary injection target) or the Fourth Panoche (the alternate injection zone) and reflect the final well construction.*
- *Comment noted. The Second and First Panoche are, respectively, the primary and secondary injection targets. The Fourth Panoche is reserved as the tertiary injection zone. Currently, using the Fourth Panoche as an injection zone is unlikely. Final well schematics will reflect actual zones selected for injection.*

### **3.6 Monitoring Well Plugging Plan**

The proposed plugging and abandonment procedures are described in Section 7.1 of Attachment E (the PISC and Site Closure Plan). The attachment describes generally the procedures CES will use to plug the monitoring wells, including removal of surface fixtures; use of appropriate materials (cements and plugs) for use in CO<sub>2</sub> environments; and performance of internal and external MITs and other logs. The application notes that well specific procedures will be developed and submitted prior to starting operations.

The plugging and abandonment procedures are generally satisfactory but, as noted above, monitoring well construction information was not provided. Without well construction details and plugging schematics, the plugging procedures are deficient and cannot be evaluated.

***Questions/Requests for CES:***

- *Please provide proposed construction details and plugging schematics for each of the monitoring wells.*

- Please refer to Appendix B in this document for updated well schematics.

### *Considerations based on the results of Pre-Operational Testing/Modeling Updates:*

- EPA will need to review the plugging procedures based on updated geologic information and construction schematics after the wells are drilled and completed.

### 3.7 Corrective Action on Wells in the AoR

Attachment B describes two wells within the AoR that penetrate the Moreno Shale confining zone: Amstar 1 (drilled into the First Panoche Sands) and BB Co. 1 (drilled to basement rock). The Attachment describes the five wellbores located within the AoR and the condition of the two deficient wellbores.

The attachment describes the process by which CES identified wells within a 2.5-mile radius of the proposed injection well, determined which wells penetrate the Moreno Shale confining zone, and reviewed drilling and abandonment records for the wells that penetrate the confining zone. It appears that CES used appropriate methods to identify all artificial penetrations throughout the AoR and the list of artificial penetrations is complete (see the AoR modeling report for additional information).

Attachment D describes the plugging procedures for the Amstar 1 and BB Co 1 wells (the two wells that require corrective action). Figures 14 and 15 from Attachment B are inserted below to illustrate the wellbore condition after the plugging procedure is completed in each wellbore.

CES

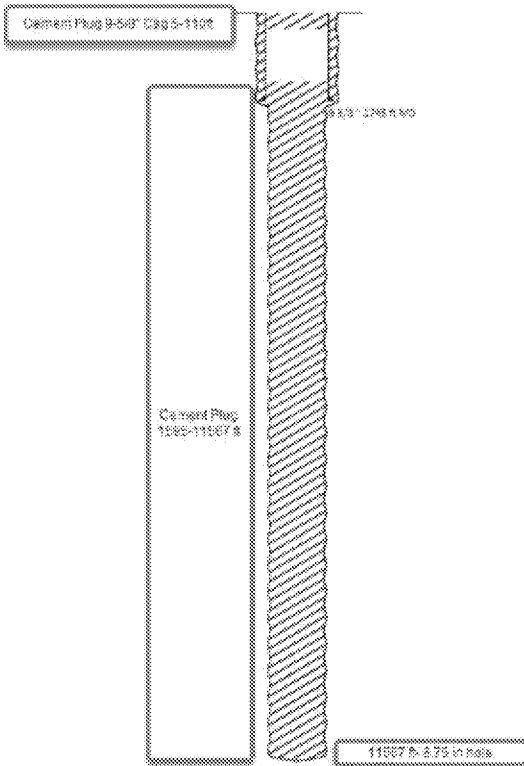


Figure 14: BB Co. 1 wellbore after P&A operation

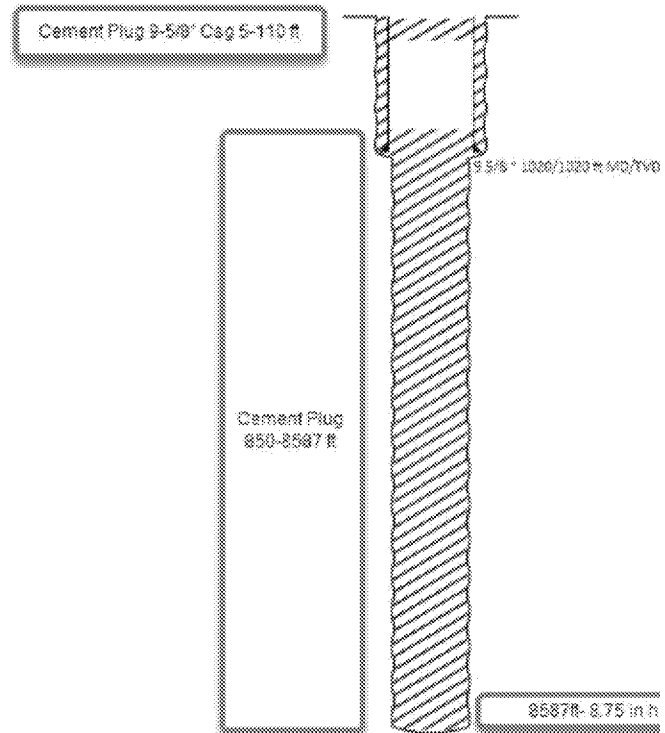


Figure 15: Amstar 1 wellbore after P&A operation

The Amstar 1 and BB Co 1 wells currently have only one relatively shallow casing installed (the Amstar 1 has a cemented surface casing at 1,020 feet and the BB Co 1 has a cemented surface casing at 1,745 feet). Each well was drilled much deeper but no production casing was installed and instead each was open-hole plugged and abandoned, meaning just a small plug of cement is present inside each well's drilled production hole. CES proposes to re-enter these two wells, drill out these plugs, and re-plug them. Under the CES proposed plan, the two wellbores would be filled with Class G cement from total depth upward into the surface casing and from 110 to 5 feet inside the surface casing. It is unclear why CES is proposing the use of Class G cement, instead of a CO<sub>2</sub> corrosion-resistant cement. The depth to the base of USDWs in each well is not provided.

- *The Amstar and BB Co 1 well plugging operations will be corrected to reflect CO<sub>2</sub>-resistant cement.*

CES proposes to re-plug and abandon the Amstar 1 well prior to injection operations because it is located within 1.5 miles of the proposed injection well while the BB Co 1 well is located more than 2.32 miles from the proposed injection well and beyond the modeled AoR. The schedule for re-plugging the BB Co 1 well is not provided except that it will be scheduled second to the Amstar 1 well.

- *Because Amstar 1 (1.4 miles from Mendota INJ 1) is much closer to the injection well than BB Company 1 is (2.14 miles from Mendota INJ 1), Amstar 1 will be plugged first because it is of higher risk. Both wells will be plugged prior to commencement of any injection activity at the Mendota INJ 1 well location.*

#### *Questions/Requests for CES:*

- *The deepest USDW (calculated at ~1,609feet bgs) is 5,700feet above the Moreno Shale which is the secondary confining zone, as stated in the application. Please provide the depth to the base of USDWs in each of the two wells to be re-plugged and abandoned for corrective action.*
- *Because of the lack of site-specific data, for the time being, the depth of the deepest USDW is estimated to be the same for both wells. There is not enough data to support location-specific USDW depths in the area. The calculations for the depth of the deepest USDW will remain uncertain until more precise methods for calculating this are available from the drilling of a characterization well which will use fluid samples and formation salinity calculations from modern logs.*
- *Please clarify whether CES proposes to re-plug and abandon the BB Co 1 well prior to commencement of injection activities.*
- *CES proposes to replug and abandon the BB Company 1 well prior to commencement of injection activities.*
- *The plugging procedures for Amstar 1 and BB Co 1 on pages 25 and 26 reference a casing diameter of 9 5/8 inches; however, figures 14 and 15 show that the hole is 8.75 inches. Please clarify the discrepancy.*
- *This is correct. The 9 5/8-in. surface casing has drift inner diameter of 8.75 in. Therefore, an 8.75-in. hole was drilled below the 9 5/8-in. casing.*
- *Given that the Amstar 1 and BB Co 1 wellbores may eventually come into contact with the injected CO<sub>2</sub>, use of a CO<sub>2</sub> corrosion-resistant cement will be required.*

- *Comment noted. Attachments and plans will be corrected accordingly.*
- *Figure 46 of the permit application narrative shows the centroids of the water well locations. Please provide verified actual locations of the water wells.*
- *Please refer to **Error! Reference source not found.** in Appendix A of this document for surface locations of GW1 to GW4 shallow monitoring wells. These are the proposed monitoring well locations that will be drilled.*

*Considerations based on the results of Pre-Operational Testing/Modeling Updates:*

- *The AoR modeling and corrective action evaluation will need to be reviewed based on confirmation of the thicknesses and depths of the injection and confining zones and the depth of the lowest USDW at the project site through seismic imaging and information gained during drilling of the injection well and deep monitoring well.*
- *Comment noted. CES intends to update all models and mitigation activities based upon subsurface confining zone depth and thickness information as it becomes available as a product of remotely acquired and direct measured geologic and geophysical data sets.*

## 4 Appendix A: Updated Tables and Figures

*This section contains updated tables and figures referred to in the comments. Updated information is shown in green in the tables. One table, Table 4-4, is a new table.*

*Table 4-1. List of equipment coupons with material of construction. Updated Table 5 of Attachment G.*

Equipment Coupon	Material of Construction
Pipeline	Carbon Steel <i>TBD</i>
Long String Casing (0-7332 ft)	Carbon Steel <i>T-95 Type 1 per API 05CT</i>
Long String Casing (7332ft – 10412ft)	Chrome Alloy <i>TN 95Cr13 Tenaris Proprietary</i>
Injection Tubing	Chrome Alloy <i>L80 13Cr per API 05CT</i>
Wellhead	<i>CO<sub>2</sub> wetted surfaces would be constructed per NACE MR0175/ISO 15156 guidelines. Currently, that is thought is to be a martensitic stainless steel 13Cr but is dependent on final CO<sub>2</sub> stream composition and testing. Wellhead bodies will be a low carbon alloy 4130.</i>
Packer	Chrome Alloy <i>CO<sub>2</sub> wetted material Super 13 stainless steel 110-ksi minimum yield strength per UNS S41425/ S41427 standards</i>

*Note: As aspects of the project become more defined the CO<sub>2</sub> stream and/or operational parameters material selections may change. Changes will be submitted for approval as they are obtained.*

*Table 4-2 Monitoring of groundwater quality and geochemical changes above the confining zone. Updated Table 6.*

Target Formation	Monitoring Activity	Monitoring Location(s)	Spatial Coverage	Frequency <sup>1-6</sup>
<i>Groundwater Quality Monitoring</i>				
Quaternary / Shallow strata sources of drinking water	Fluid sampling	Shallow monitoring wells GW1, GW2, GW3, GW4	4 shallow monitoring wells each with one sampling interval	Baseline: Quarterly Year 1-2: Quarterly Year 3-injection end: Quarterly Year 3-5 years post injection: Annual
Santa Margarita or base of USDW (~1616 ft MD)	Fluid sampling	Mendota USDW 1	1-point location	Baseline: Quarterly Year 1-2: Quarterly Year 3-injection end: Quarterly 3-5 years post injection: Annual
<i>Well Integrity Monitoring</i>				
Garzas (5804-7332 ft MD)	Fluid sampling	Mendota ACZ 1	Distributed measurement	Baseline: Quarterly Year 1-2: Quarterly Year 3-5: Quarterly Year 6-injection end: Annual 3-5 years post injection: Quarterly
First and Second Panoche (8437-9757 ft MD)	Fluid sampling	Mendota OBS 1	1 point location	Baseline; Year 1-end of injection: Annual

Garzas (5804-7332 ft MD)	DAS – Distributed Temperature / Acoustic	Mendota ACZ 1	Distributed measurement	Continuous
First and Second Panoche (8437-9757 ft MD)	DAS – Distributed Temperature / Acoustic	Mendota OBS 1	Distributed measurement	Continuous
Garzas (5804-7332 ft MD)	Pulsed Neutron	Mendota ACZ 1	Survey Log	Baseline; Year 1-1.5: Quarterly Year 1.5- through injection period: Annual
First and Second Panoche (8437-9757 ft MD)	Pulsed Neutron	Mendota OBS 1	Survey Log	Baseline; Year 1-1.5: Quarterly Year 1.5- through injection period: Annual
First and Second Panoche (8437-9757 ft MD)	<i>Pulsed Neutron</i>	<i>INJ-1</i>	<i>Survey Log</i>	<i>Baseline; Year 0-1.5: Quarterly Year 1.5- through injection period: Annual</i>

Note 1: Baseline is prior to CO<sub>2</sub> injection. Baseline sampling and analysis will be completed before injection is authorized.

Note 2: Year 1 is from initial CO<sub>2</sub> injection through 1 year.

Note 3: Quarterly sampling will take place by the following dates each year: 3 months after the date of authorization of injection, 6 months after the date of authorization of injection, 9 months after the date of authorization of injection, and 12 months after the date of authorization of injection.

Note 4: Semi-annual sampling will be performed each year by: 6 months after the date of authorization of injection and 12 months after the date of authorization of injection.

Note 5: Annual sampling will occur up to 45 days before the anniversary date of authorization of injection each year.

Note 6: Continuous monitoring is described in Table 2 of this plan.

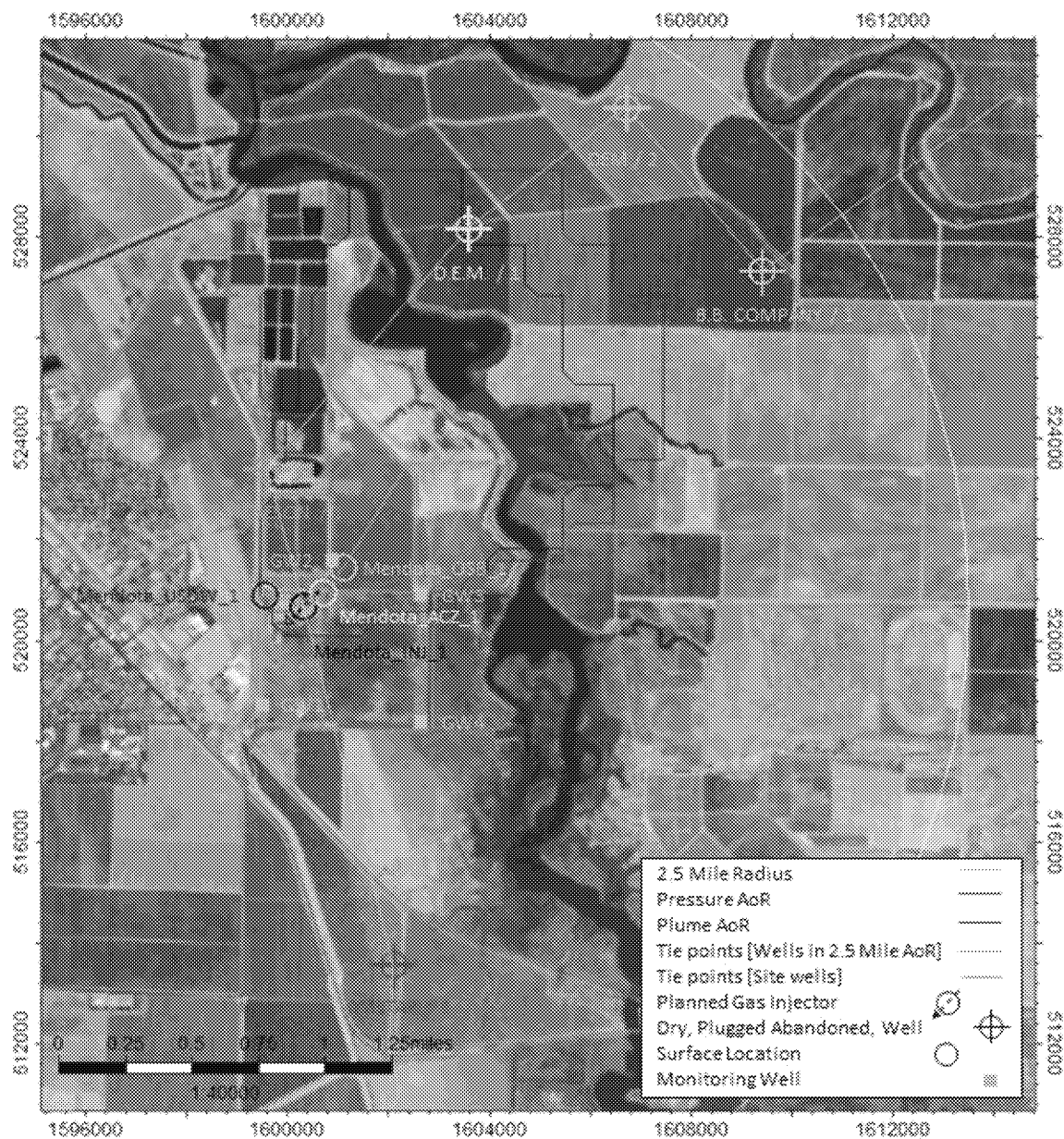
Note 7: Changes to the ground water monitoring frequency will be with the UIC Program Directors prior approval.

Table 4-3. Mendota INJ 1 casing details. Updated Table 14.

Casing String	Casing Depth	Borehole Diameter	Wall Thickness	External Diameter	Casing Material	String Weight
Conductor	86 ft	26 in	1 in	22 in	197.41 ppf Grade: B Connection: Welded	16997 lbs
Surface	1800 ft	20 in	0.875 in	16 in	84 ppf Grade: N80 Connection: Tenaris ER	151200 lbs
Intermediate String	7432 ft	14.75 in	0.495 in	10.75 in	55.5 ppf Grade: N80 Connection: Tenaris Blue	412476 lbs
Long String	7332	9.625 in	0.590 in	7.0 in	38 ppf Grade: T-95 Type1 Connection: Tenaris Blue	422792 lbs
	10412	9.625 in	0.590 in	7.0 in	38 ppf Grade: T95-13Cr Connection: Tenaris Blue	

Table 4-4. Surface location of proposed shallow water wells at Mendota site (new table)

Name	Surface X	Surface Y	Latitude	Longitude
GW1	1599623	518588	36.75005	-120.367
GW2	1600901	521506.4	36.75812	-120.362
GW3	1602629	520922.9	36.75658	-120.356
GW4	1602636	518402.3	36.74966	-120.356

Figure 4-1. Mendota site location map with CO<sub>2</sub> and pressure AoR (combination of maps from Figure 12 Attachment B and Figure 1 Attachment C of the original submission).

## **5 Appendix B: Monitoring and Injection Well Schematics and Casing, Tubing, and Packer Specifications**

*This section contains well schematics and casing, tubing, packer, and plugging specifications, as appropriate, for the following wells:*

- ✧ *Mendota INJ 1*
- ✧ *Mendota USDW 1*
- ✧ *GW 1-4*
- ✧ *Mendota OBS 1*
- ✧ *Mendota ACZ 1*

*The well schematics are not drawn to the scale. Refer to the reference depths on the figures for formation tops and equipment and cementing locations.*

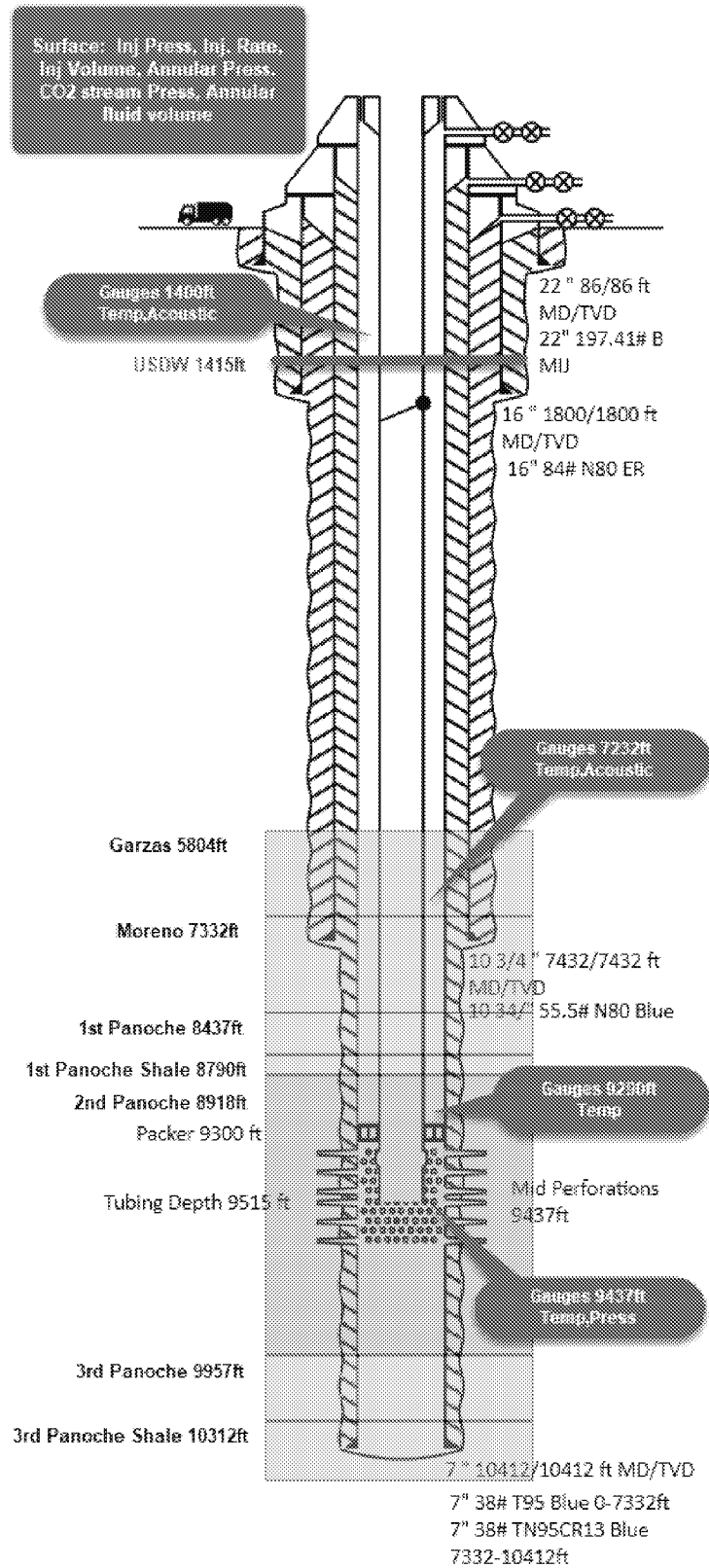


Figure 5-1. Mendota INJ 1 well schematic, including gauges and USDW. Updated figure.

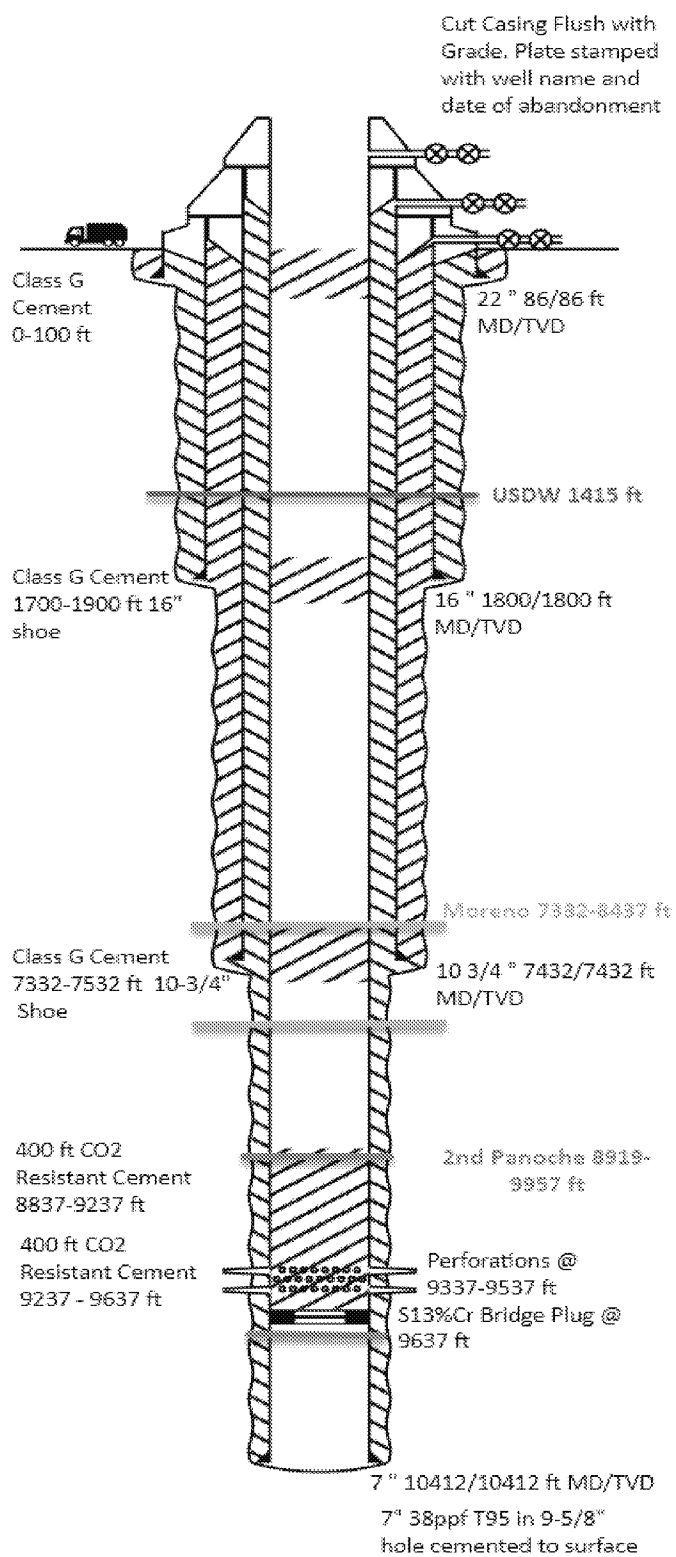


Figure 5-2. Plug and abandonment schematic, Mendota INJ 1, updated to reflect formation top sand cement plug configurations. Updated figure.

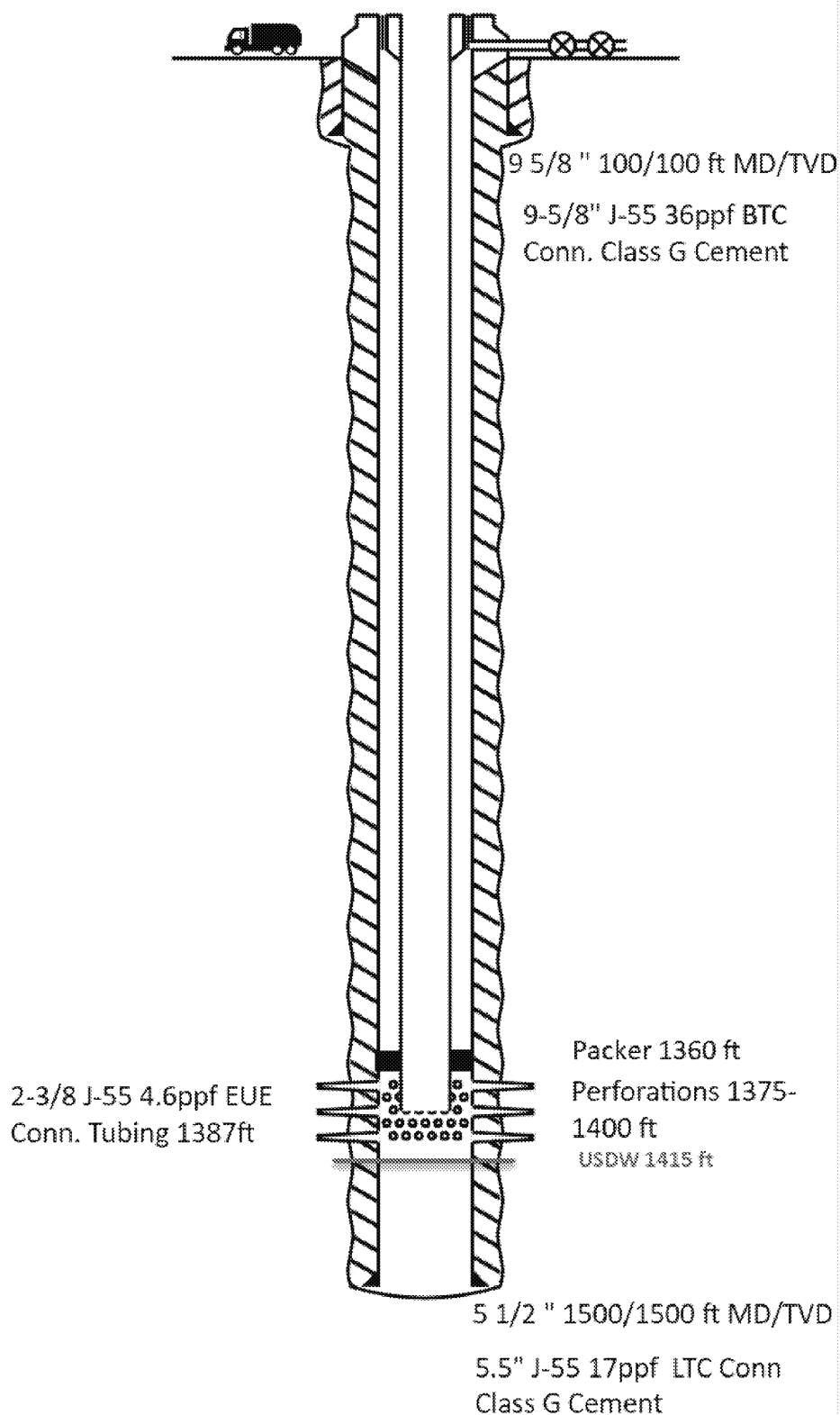


Figure 5-3. Mendota USDW 1 well schematic. New figure.

Table 5-1. Mendota USDW 1 Casing description (Table 2 from the original submission with no changes).

Name	Depth Interval	Open Hole Diameter	Comment
	(feet)	(inches)	
Conductor	86	16	Conductor will be augered with 16" hole and cement grouted in annulus
Surface	9851	8.75	1500 ft will cover any potential freshwater aquifers The lowest USDW level is estimated to be 1415 ft. The string will be perforated or allow monitoring of the USDW Length may vary slightly in locating a formation with sufficient strength to provide a competent casing shoe.

Table 5-2. Mendota USDW 1 casing specifications (Table 4 from the original submission with no changes).

Name	Depth Interval	Outside Diameter	Inside Diameter	Weight	Grade	Design Coupling	Thermal Conductivity	Burst Strength	Collapse Strength
	(feet)	(inches)	(inches)	(lb/ft)	(API)	(Short or Long Threaded)	(@ 77°F (BTU/ft hr, °F))	(psi)	(psi)
Conductor	86	9.625	8.921	36	J-55	Long	26.13	3520	2020
Surface	1800	5.5	4.892	17	J-55	Long	26.13	5320	4910

Table 5-3. Mendota USDW 1 tubing specifications (Table 5 of the original submission with no changes).

Name	Depth Interval	Outside Diameter	Inside Diameter	Weight	Grade	Design Coupling	Burst strength	Collapse strength
	(feet)	(inches)	(inches)	(lb/ft)	(API)	(Short or Long Thread)	(psi)	(psi)
2-3/8 Tubing	1387	2.375	1.995	4.6	J-55	Long	7700	8100

Table 5-4. Mendota USDW 1 packer specification (Table 6 of the original submission with no changes).

Packer Type and Material	Packer Setting Depth	Length	Nominal Casing Weight	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
	(feet bgs)	(inches)	(lbs/ft)		
Cast Iron Weld on for Water Well	1360	6	17	N/A	N/A

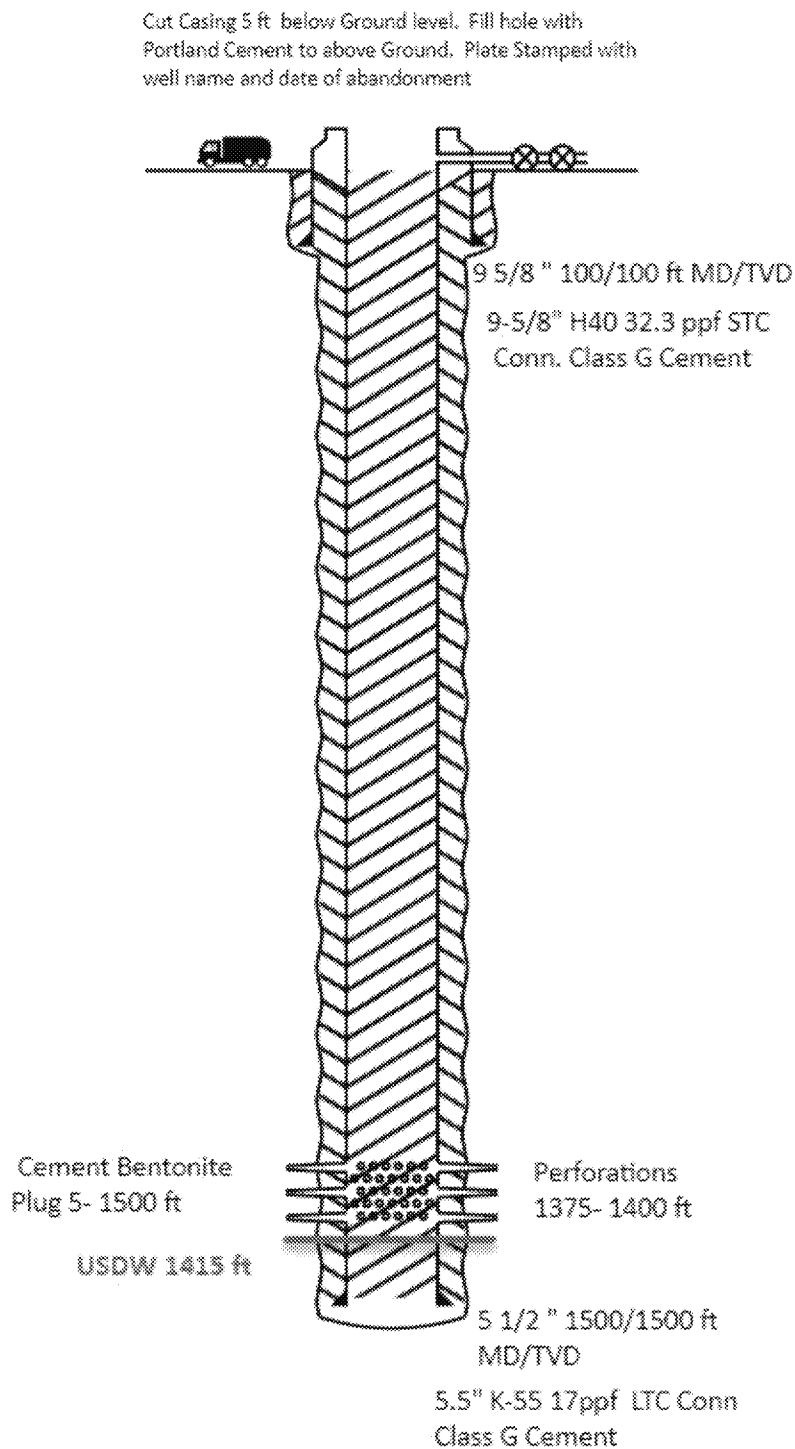


Figure 5-4. Plug and abandon schematic Mendota USDW 1. New figure.

*Table 5-5. Mendota USDW 1 plugging specification (Table 7 of the original submission with no change).*

<b>Plug Information</b>	<b>Plug #1</b>
Diameter of boring in which plug will be placed (in.)	4.892
Depth to bottom of tubing or drill pipe (ft)	1500
Sacks of cement to be used (each plug)	105
Slurry volume to be pumped (bbl)	34.8
Slurry weight (lb./gal)	12.6
Calculated top of plug (ft)	5
Bottom of plug (ft)	1500
Type of cement or other material	Class A/Bentonite
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced

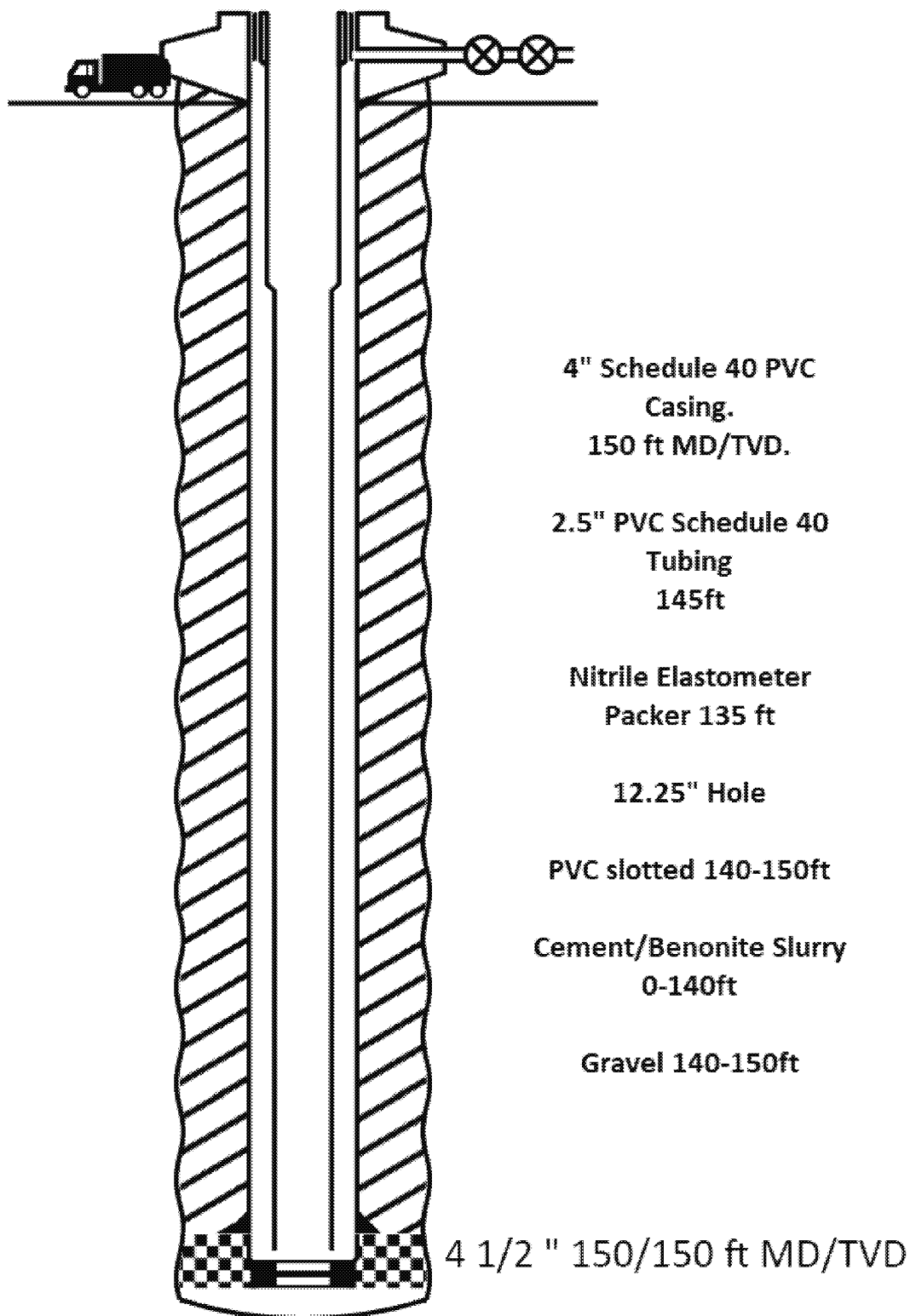


Figure 5-5. Plug and abandonment GW 1-4 well schematic. New figure.

Cut Casing 5 ft below Ground level. Fill hole with Portland Cement to above Ground. Plate Stamped with well name and date of abandonment

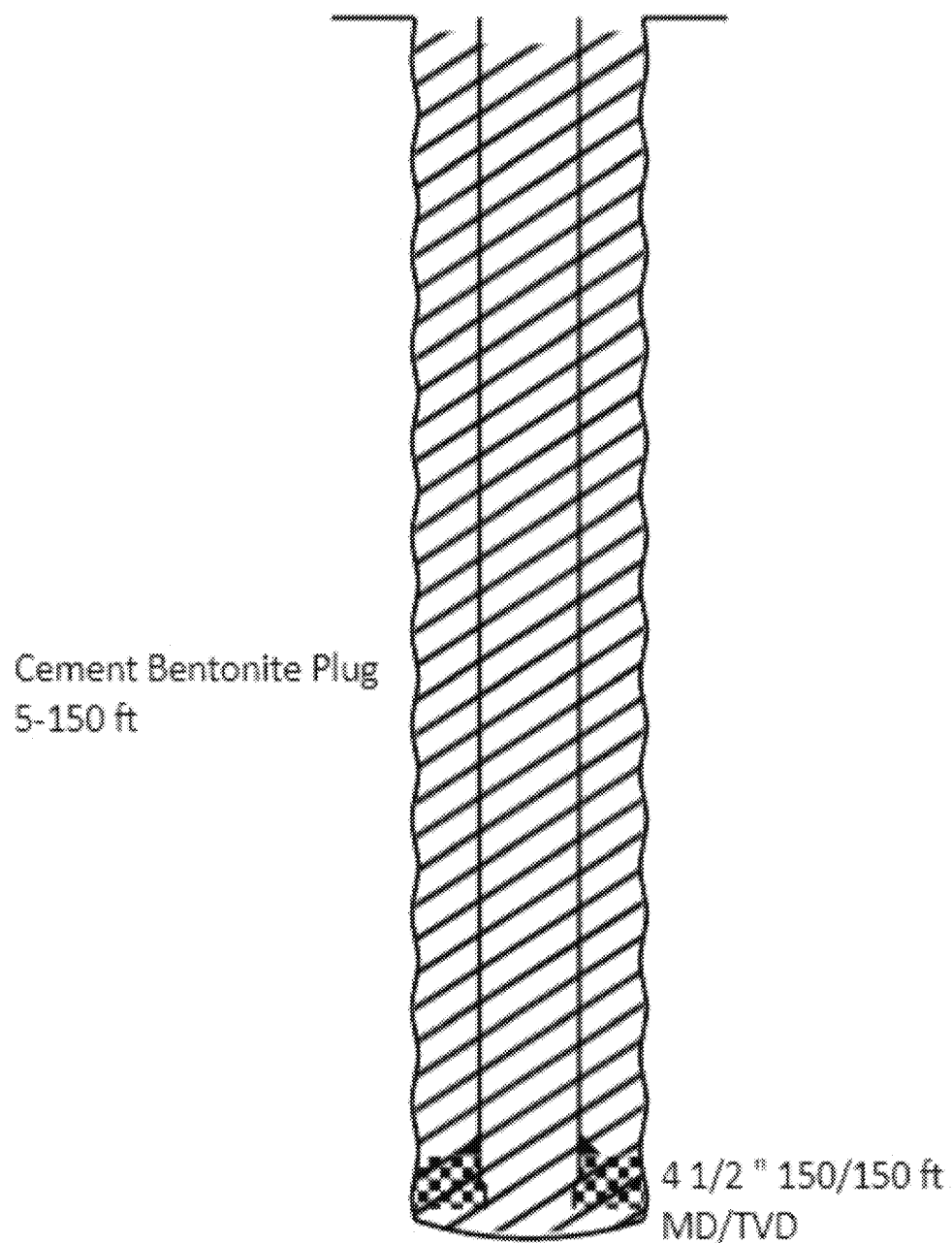


Figure 5-6. GW 1-4 plug and abandon. New figure.

*Table 5-6. Mendota GW 1-4 plugging specification (original Table 8 with no changes)*

<b>Plug Information</b>	<b>Plug #1</b>
Diameter of boring in which plug will be placed (in.)	4.00
Depth to bottom of tubing or drill pipe (ft)	150
Sacks of cement to be used (each plug)	7
Slurry volume to be pumped (bbl)	2.33
Slurry weight (lb./gal)	12.6
Calculated top of plug (ft)	5
Bottom of plug (ft)	150
Type of cement or other material	Class A/Bentonite
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced

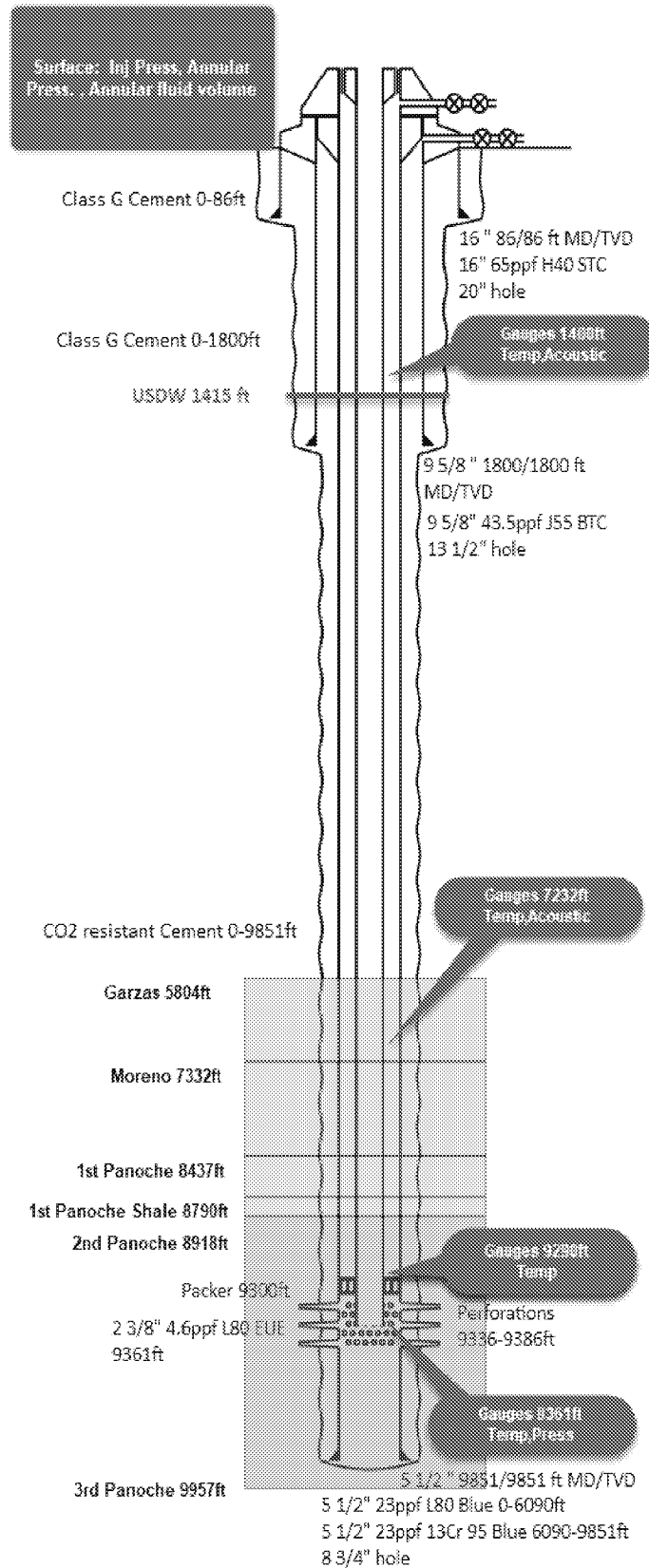


Figure 5-7. Mendota OBS 1 monitoring well schematic. New figure.

Table 5-7. Mendota OBS 1 casing description (original Table 9 with no changes)

Name	Depth Interval	Open Hole Diameter	Comment
	(feet)	(inches)	
Conductor	86	20	Conductor will be augered with 20" hole and cement grouted in annulus
Surface	1800	13.5	1800 ft will cover any potential freshwater aquifers and provide sufficient kick tolerance for the intermediate string. Length may vary slightly in locating a formation with sufficient strength to provide a competent casing shoe.
Long-string	9851	8.5	Casing shoe will be set at the lower end of the 2 <sup>nd</sup> Panoche Sands for monitoring purposes

Table 5-8. Mendota OBS 1 casing specification (original Table 10 with no changes)

Name	Depth Interval	Outside Diameter	Inside Diameter	Weight	Grade	Design Coupling	Thermal Conductivity	Burst Strength	Collapse Strength
	(feet)	(inches)	(inches)	(lb/ft)	(API)	(Short or Long Threaded)	@ 77°F (BTU/ft hr, °F)	(psi)	(psi)
Conductor	86	16	15.2	65	H40	Short	26.13	1640	63
Surface	1800	9.625	8.755	43.5	J55	Long	26.13	4350	3250
Long-string	0-6090	5.5	4.892	23	L80	Long	26.13	7740	6290
Long-string	6090-9851	5.5	4.892	23	TN 95 13Cr	Long	26.13	12540	12930

Table 5-9. Mendota tubing specification (original Table 11 with no changes).

Name	Depth Interval	Outside Diameter	Inside Diameter	Weight	Grade	Design Coupling	Burst strength	Collapse strength
	(feet)	(inches)	(inches)	(lb/ft)	(API)	(Short or Long Thread)	(psi)	(psi)
2-3/8 Tubing	7219	2.375	1.995	4.6	L80 13Cr	Long	11200	11780

Table 5-10. Mendota OBS 1 Packer Specification (original Table 12 with no changes)

Packer Type and Material	Packer Setting Depth	Length	Nominal Casing Weight	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
	(feet bgs)	(inches)	(lbs/ft)		
Seal Bore Packer Super 13Cr	9300	64	23	4.437	3.003

Table 5-11. Mendota OBS 1 packer rating (original Table 13 with no changes)

Tensile Rating	Burst Rating	Collapse Rating	Max. Casing Inner Diameter	Min. Casing Inner Diameter
(lbs)	(psi)	(psi)	(inches)	(inches)
133.12@250degF	10000	10000	4.778	4.670

Cut Casing 5 ft below Ground Level. Fill hole with Portland Cement to above Ground. Plate Stamped with well name and date of abandonment

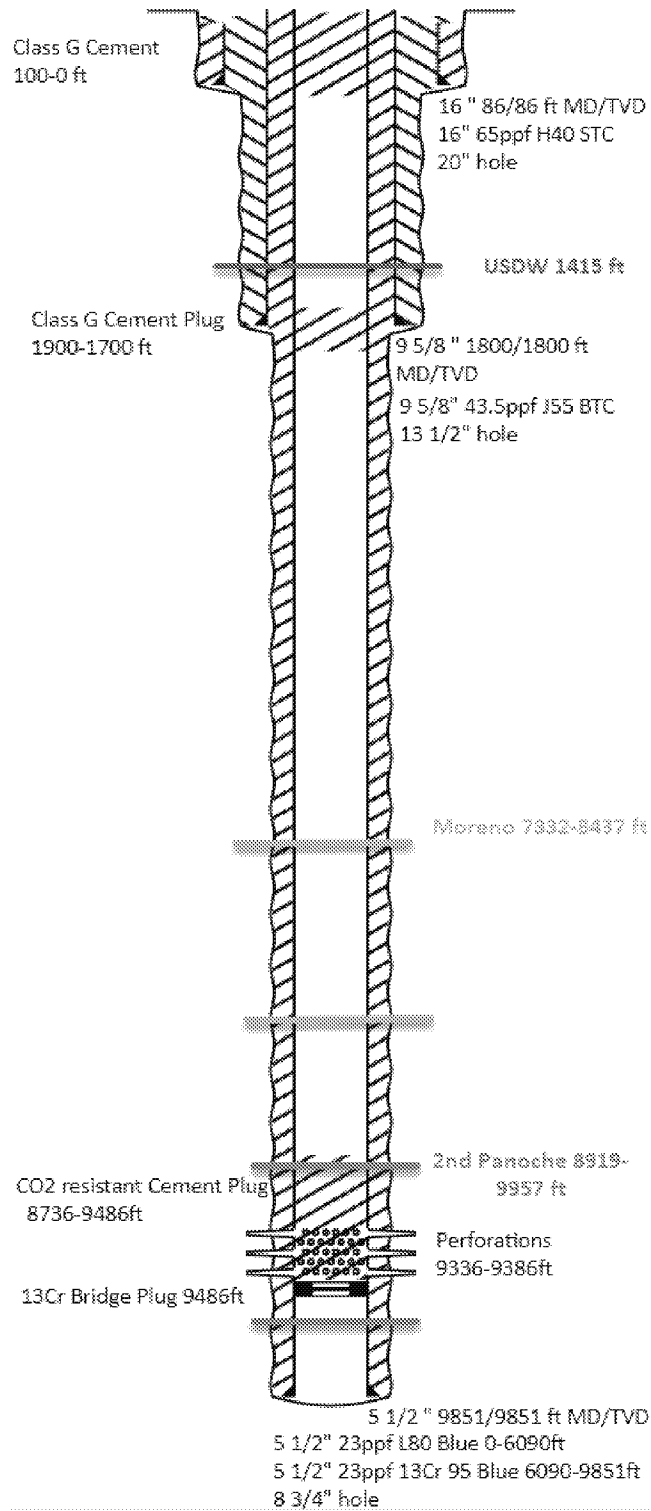


Figure 5-8. Mendota OBS 1 monitor well plug and abandon. New figure.

*Table 5-12. Mendota OBS I plugging specification (original Table 14 with no changes).*

<b>Plug Information</b>	<b>Plug #1</b>	<b>Plug #2</b>	<b>Plug #3</b>
Diameter of boring in which plug will be placed (in.)	4.670	4.670	4.670
Depth to bottom of tubing or drill pipe (ft)	9851	9851	9851
Sacks of cement to be used (each plug)	73.8	19.63	9.77
Slurry volume to be pumped (bbl)	15.9	4.23	2.11
Slurry weight (lb./gal)	15.8	15.8	15.8
Calculated top of plug (ft)	8736	1700	5
Bottom of plug (ft)	9486	1900	100
Type of cement or other material	CO2 Resistant	Class G	Class G
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced	Balanced	Balanced

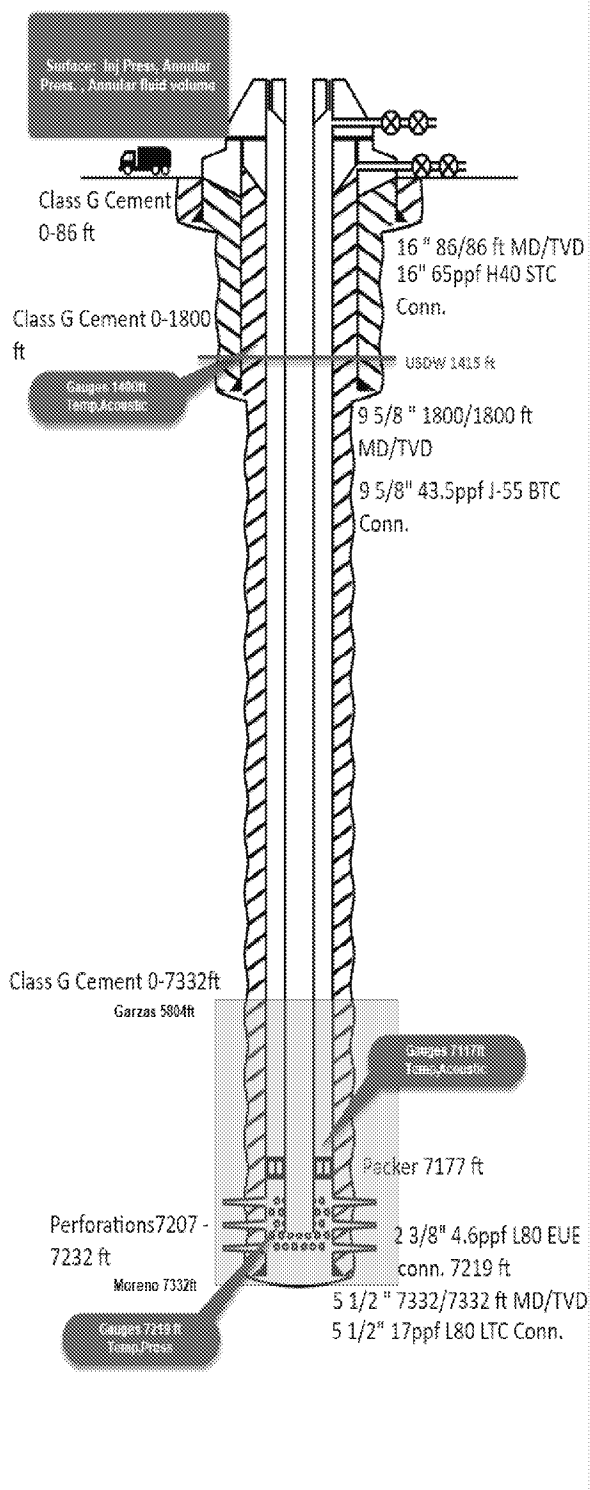


Figure 5-9. Mendota ACZ 1 well schematic. New figure.

Table 5-13. Mendota ACZ I casing description (original Table 15 with no changes).

Name	Depth Interval	Open Hole Diameter	Comment
	(feet)	(inches)	
Conductor	86	20	Conductor will be augered with 20" hole and cement grouted in annulus
Surface	1800	13.5	1800 ft will cover any potential freshwater aquifers and provide sufficient kick tolerance for the intermediate string. Length may vary slightly in locating a formation with sufficient strength to provide a competent casing shoe.
Long-string	7332	8.5	Casing shoe will be set at the bottom of the Garzas Sands for monitoring purposes

Table 5-14. Mendota ACZ I casing specifications (original Table 16 with no changes).

Name	Depth Interval	Outside Diameter	Inside Diameter	Weight	Grade	Design Coupling	Thermal Conductivity	Burst Strength	Collapse Strength
	(feet)	(inches)	(inches)	(lb/ft)	(API)	(Short or Long Threaded)	@ 77°F (BTU/ft hr, °F)	(psi)	(psi)
Conductor	86	16	15.2	65	H40	Short	26.13	1640	63
Surface	1800	9.625	8.755	43.5	J55	Long	26.13	4350	3250
Long-string	7332	5.5	4.892	17	L80	Long	26.13	7740	6290

Table 5-15. Mendota ACZ I tubing specification (original Table 17 with no changes).

Name	Depth Interval	Outside Diameter	Inside Diameter	Weight	Grade	Design Coupling	Burst strength	Collapse strength
	(feet)	(inches)	(inches)	(lb/ft)	(API)	(Short or Long Thread)	(psi)	(psi)
2-3/8 Tubing	7219	2.375	1.995	4.6	L80	Long	11200	11780

Table 5-16 Mendota ACZ 1 packer specifications (original Table 18 with no changes).

Packer Type and Material	Packer Setting Depth	Length	Nominal Casing Weight	Packer Main Body Outer Diameter (inches)	Packer Inner Diameter (inches)
	(feet bgs)	(inches)	(lbs/ft)		
Seal Bore Packer Low Carbon Alloy Steel	7717	64	17	4.563	3.003

Table 5-17. Mendota ACZ 1 packer rating (original Table 19 with no changes).

Tensile Rating	Burst Rating	Collapse Rating	Max. Casing Inner Diameter	Min. Casing Inner Diameter
(lbs)	(psi)	(psi)	(inches)	(inches)
133.12@250degF	10000	10000	5.012	4.892

Cut Casing 5 ft below Ground Level. Fill hole with Portland Cement to above Ground. Plate Stamped with well name and date of abandonment

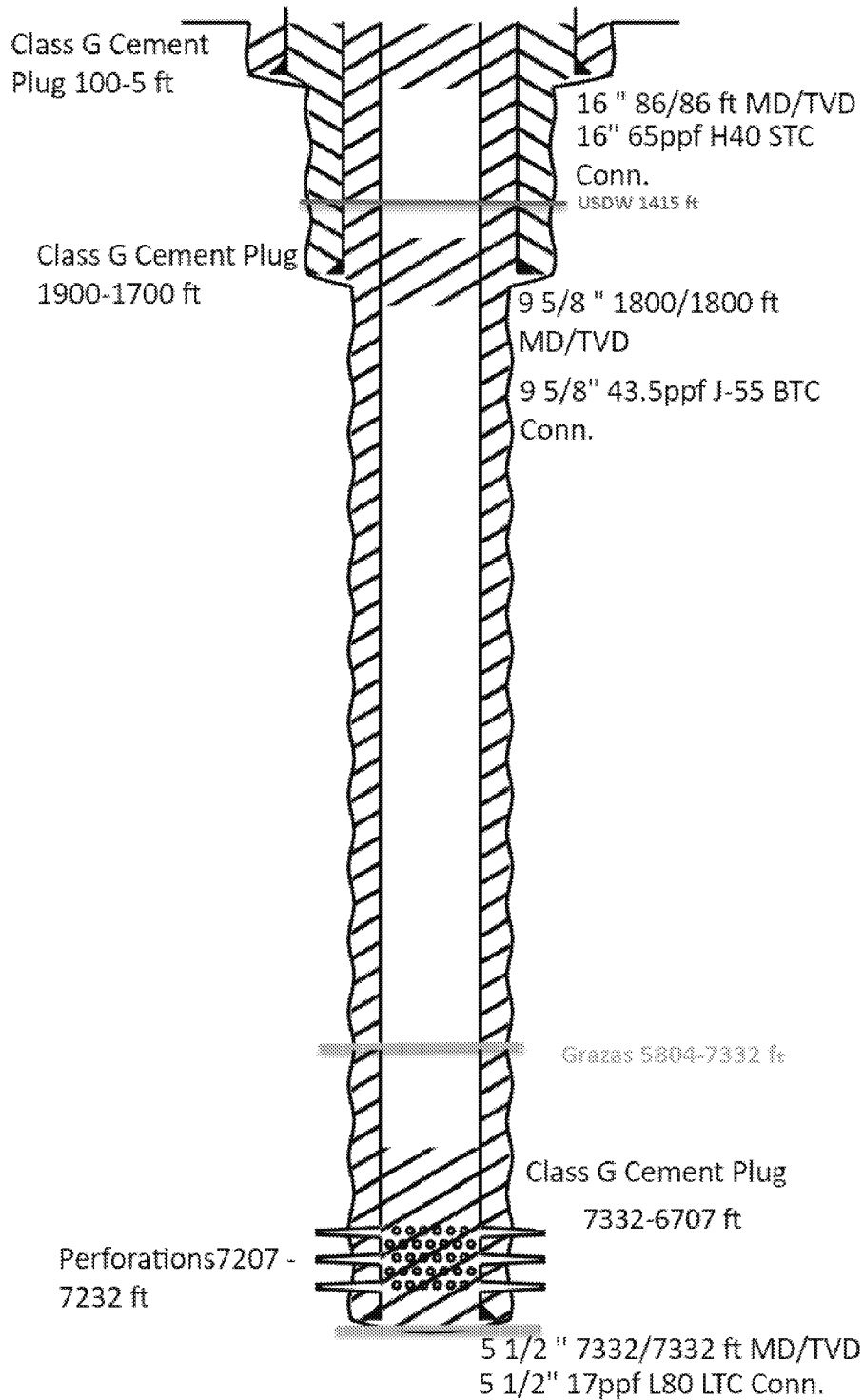


Figure 5-10. Mendota ACZ 1 plug and abandon. New figure.

*Table 5-18. Mendota ACZ I plugging specifications (original table 20 with no changes).*

<b>Plug Information</b>	<b>Plug #1</b>	<b>Plug #2</b>	<b>Plug #3</b>
Diameter of boring in which plug will be placed (in.)	4.892	4.892	4.892
Depth to bottom of tubing or drill pipe (ft)	7332	7332	7332
Sacks of cement to be used (each plug)	67.3	21.48	10.74
Slurry volume to be pumped (bbl)	14.52	4.64	2.32
Slurry weight (lb./gal)	15.8	15.8	15.8
Calculated top of plug (ft)	6707	1700	5
Bottom of plug (ft)	7332	1900	100
Type of cement or other material	Class G	Class G	Class G
Method of emplacement (e.g., balance method, retainer method, or two-plug method)	Balanced	Balanced	Balanced

## 6 Appendix C: Updated Pressure Falloff Test Procedures

### 6.1 Purpose

The purpose of this test is to identify injection interval or wellbore problems and injection interval characteristics. It is the responsibility of the permittee to develop a testing procedure which will generate adequate data for a meaningful analysis.

### 6.2 Regulatory Citation

The Class VI Rule requires monitoring of the pressure buildup in the injection zone at least every five (5) years and more frequently if required by the UIC program director [40 CFR 146.90(f), including at a minimum, shut down of the well for a time sufficient to conduct a valid observation of the pressure falloff. This test is known as the formation pressure falloff test.

### 6.3 Timing of Falloff Tests and Submission

Falloff tests must be conducted within one year from the date of the original petition approval and annually thereafter. The time interval for each test should not be less than 9 months or greater than 15 months from the previous test. This will ensure that the tests will be performed at relatively even intervals throughout the duration of the petition approval period. Operators can, at their discretion, plan these tests to coincide with the performance of their annual state MIT requirements as long as the time requirements are met. The falloff testing report should be submitted no later than 60 days following the test. Failure to submit a falloff test report will be considered a violation of the applicable petition condition and may result in an enforcement action. Any exceptions should be approved by EPA prior to conducting the test.

### 6.4 Fall Off Test Report Requirements

In general, the report to EPA should provide general information and an overview of the falloff test, an analysis of the pressure data obtained during the test, a summary of the test results, and a comparison of the results with the parameters used in the no migration demonstration. Some of the following operator and well data will not change so once acquired, it can be copied and submitted with each annual report. The falloff test report should include the following information:

1. Company name and address
2. Test well name and location
3. The name and phone number of the facility contact person. The contractor contact may be included if approved by the facility in addition to a facility contact person.
4. A photocopy of an openhole log (SP or gamma ray) through the injection interval illustrating the type of formation and thickness of the injection interval. The entire log is not necessary.
5. Well schematic showing the current wellbore configuration and completion information:
  - Wellbore radius
  - Completed interval depths
  - Type of completion (perforated, screen and gravel packed, openhole)

6. Depth of fill depth and date tagged.
7. Offset well information:
  - Distance between the test well and offset well(s) completed in the same interval or involved in an interference test
  - Simple illustration of locations of the injection and offset wells
8. Chronological listing of daily testing activities.
9. Electronic submission of the raw data (time, pressure, and temperature) from all pressure gauges utilized on a floppy disk or CD-ROM. A READ.ME file or the disk label should list all files included and any necessary explanations of the data. A separate file containing any edited data used in the analysis can be submitted as an additional file.
10. Tabular summary of the injection rate or rates preceding the falloff test. At a minimum, rate information for 48 hours prior to the falloff or for a time equal to twice the time of the falloff test is recommended. If the rates varied and the rate information is greater than 10 entries, the rate data should be submitted electronically as well as a hard copy of the rates for the report. Including a rate vs time plot is also a good way to illustrate the magnitude and number of rate changes prior to the falloff test.
11. Rate information from any offset wells completed in the same interval. At a minimum, the injection rate data for the 48 hours preceding the falloff test should be included in a tabular and electronic format. Adding a rate vs time plot is also helpful to illustrate the rate changes.
12. Hard copy of the time and pressure data analyzed in the report.
13. Pressure gauge information:
  - List all the gauges utilized to test the well
  - Depth of each gauge
  - Manufacturer and type of gauge. Include the full range of the gauge.
  - Resolution and accuracy of the gauge as a % of full range.
  - Calibration certificate and manufacturer's recommended frequency of calibration
14. General test information:
  - Date of the test
  - Time synchronization: A specific time and date should be synchronized to an equivalent time in each pressure file submitted. Time synchronization should also be provided for the rate(s) of the test well and any offset wells.
  - Location of the shut-in valve (e.g., note if at the wellhead or number of feet from the wellhead)
15. Reservoir parameters (determination) :
  - Formation fluid viscosity,  $\mu_f$  cp (direct measurement or correlation)
  - Porosity,  $\phi$  fraction (well log correlation or core data)
  - Total compressibility,  $c_t$  psi<sup>-1</sup> (correlations, core measurement, or well test)
  - Formation volume factor,  $r_{vb}/stb$  (correlations, usually assumed 1 for water)
  - Initial formation reservoir pressure
  - Date reservoir pressure was last stabilized (injection history)
  - Justified interval thickness,  $h$  ft
16. Waste plume
  - Cumulative injection volume into the completed interval
  - Calculated radial distance to the waste front

- Average historical waste fluid viscosity, if used in the analysis
17. Injection period:
- Time of injection period
  - Type of test fluid
  - Type of pump used for the test (e.g., plant or pump truck)
  - Type of rate meter used
  - Final injection pressure and temperature
18. Falloff period:
- Total shut-in time, expressed in real time and elapsed time
  - Final shut-in pressure and temperature
  - Time well went on vacuum, if applicable
19. Pressure gradient:
- Gradient stops - for depth correction
20. Calculated test data: include all equations used and the parameter values assigned for each variable within the report
- Radius of investigation
  - Slope or slopes from the semilog plot
  - Transmissibility
  - Permeability
  - Calculation of skin
  - Calculation of skin pressure drop
  - Discussion and justification of any reservoir or outer boundary models used to simulate the test
  - Explanation for any pressure or temperature anomaly if observed
21. Graphs:
- Cartesian plot: pressure and temperature vs. time
  - Log-log diagnostic plot: pressure and semilog derivative curves. Radial flow regime should be identified on the plot
  - Semilog and expanded semilog plots: radial flow regime indicated and the semilog straight line drawn
  - Injection rate(s) vs time: test well and offset wells (not a circular or strip chart)
22. A comparison of all parameters with those used in the petition demonstration, including references where the parameters can be found in the petition.
23. A copy of the latest radioactive tracer run to fulfill the annual mechanical integrity testing requirement for the State and a brief discussion of the results.
24. Compliance with any unusual petition approval conditions such as the submission of an annual flow profile survey. These additional conditions may be addressed either in the annual falloff testing report or in an accompanying document.

## 6.5 Planning

The radial flow portion of the test is the basis for all pressure transient calculations. Therefore, the injectivity and falloff portions of the test should be designed not only to reach radial flow, but to sustain a time frame sufficient for analysis of the radial flow period.

### General Operational Concerns

Successful well testing involves the consideration of many factors, most of which are within the

operator's control. Some considerations in the planning of a test include:

- Adequate storage for the waste should be ensured for the duration of the test
- Offset wells completed in the same formation as the test well should be shut-in, or at a minimum, provisions should be made to maintain a constant injection rate prior to and during the test
- Install a crown valve on the well prior to starting the test so the well does not have to be shut-in to install a pressure gauge
- The location of the shut-in valve on the well should be at or near the wellhead to minimize the wellbore storage period
- The condition of the well, junk in the hole, wellbore fill or the degree of wellbore damage (as measured by skin) may impact the length of time the well must be shut-in for a valid falloff test. This is especially critical for wells completed in relatively low transmissibility reservoirs or wells that have large skin factors.
- Cleaning out the well and acidizing may reduce the wellbore storage period and therefore the shut-in time of the well
- Accurate recordkeeping of injection rates is critical including a mechanism to synchronize times reported for injection rate and pressure data. The elapsed time format usually reported for pressure data does not allow an easy synchronization with real time rate information. Time synchronization of the data is especially critical when the analysis includes the consideration of injection from more than one well.
- Any unorthodox testing procedure, or any testing of a well with known or anticipated problems, should be discussed with EPA staff prior to performing the test.
- Other pressure transient tests may be used in conjunction or in place of a falloff test in some situations. For example, if surface pressure measurements must be used because of a corrosive wastestream and the well will go on vacuum following shut-in, a multi-rate test may be used so that a positive surface pressure is maintained at the well. However, other pressure transient tests will be subject to EPA approval prior to the application.
- If more than one well is completed into the same reservoir, operators are encouraged to send at least two pulses to the test well by way of rate changes in the offset well following the falloff test. These pulses will demonstrate communication between the wells and, if maintained for sufficient duration, they can be analyzed as an interference test to obtain interwell reservoir parameters.

## 6.6 Pretest Planning

1. Determine the time needed to reach radial flow during the injectivity and falloff portions of the test:
  - Review previous well tests, if available
  - Simulate the test using measured or estimated reservoir and well completion parameters
  - Calculate the time to the beginning of radial flow using the empirically-based equations provided in EPA Region 9 falloff testing guideline (<https://archive.epa.gov/region9/water/archive/web/pdf/falloff-testing-guidelines.pdf>). The equations are different for the injectivity and falloff portions of the test with the skin factor influencing the falloff more than the injection period.

- Allow adequate time beyond the beginning of radial flow to observe radial flow so that a well-developed semi log straight line occurs. A good rule of thumb is 3 to 5 times the time to reach radial flow to provide adequate radial flow data for analysis.
2. Adequate and consistent injection fluid should be available so that the injection rate into the test well can be held constant prior to the falloff. This rate should be high enough to produce a measurable falloff at the test well given the resolution of the pressure gauge selected. The properties of the fluid should be consistent. Any mobility issues should be identified and addressed in the analysis if necessary.
  3. Bottomhole pressure measurements are required.
  4. Use two pressure gauges during the test with one gauge serving as a backup, or for verification in cases of questionable data quality. The two gauges do not need to be the same type.

## 6.7 Conducting the Falloff Test

1. Tag and record the depth to any fill in the test well
2. Simplify the pressure transients in the reservoir
  - Maintain a constant injection rate in the test well prior to shut-in. This injection rate should be high enough and maintained for a sufficient duration to produce a measurable pressure transient that will result in a valid falloff test.
  - Offset wells should be shut-in prior to and during the test. If shut-in is not feasible, a constant injection rate should be recorded and maintained during the test and then accounted for in the analysis.
  - Do not shut-in two wells simultaneously or change the rate in an offset well during the test.
3. The well must be shut-in at the wellhead or as near to the wellhead as feasible in order to minimize wellbore storage and after flow. The shut-in must be accomplished as instantaneously as possible to prevent erratic pressure behavior during the test.
4. Maintain accurate rate records for the test well and any offset wells completed in the same injection interval.
5. Measure and record the properties of the injectate periodically during the injectivity portion of the test to confirm the consistency of the test fluid.
6. The surface readout downhole pressure gauge must be located at or near the top of the injection interval, unless previous testing indicates a more appropriate location. A surface readout should be provided to allow flexibility in determining appropriate pressure measuring and recording time intervals and to ensure valid test data is generated and false testing runs can be identified and aborted.
7. The injection rate and injection liquid density for the test must be held constant prior to shut-in.
8. The injection rate must be high enough and continuous for a period of time sufficient to produce a pressure buildup that will result in valid test data.
9. The injection rate must result in a pressure buildup such that a semi log straight line can be determined from the Horner plot. The injection rate should be the maximum injection rate that can be feasibly maintained constant in order to maximize pressure changes in the formation and provide valid test results, but the injection pressure will not exceed the maximum allowable surface injection pressure specified in the permit.

10. If the stabilization injection period is interrupted, for any reason and for any length of time, the stabilization injection period must be restarted.
11. The falloff portion of the test must be conducted for a length of time sufficient such that the pressure is no longer influenced by wellbore storage or skin effects and enough data points lie within the infinite acting period and the semi log straight line is well developed.

## 6.8 Evaluation of the Test Results

A licensed geologist or licensed professional engineer, licensed by the Board for Professional Engineers, Land Surveyors, and Geologists to practice geology or engineering in California and knowledgeable in the methods of pressure transient test analysis, must evaluate the test results.

1. The following information and evaluations must be provided with the test report:
  - Prepare a Cartesian plot of the pressure and temperature versus real time or elapsed time.
  - Confirm pressure stabilization prior to shut-in of the test well
2. Look for anomalous data, pressure drop at the end of the test, determine if pressure drop is within the gauge resolution
3. Prepare a log-log diagnostic plot of the pressure and semi log derivative. Identify the flow
  - regimes present in the well test
  - Use the appropriate time function depending on the length of the injection period and variation in the injection rate preceding the falloff
  - Mark the various flow regimes - particularly the radial flow period
  - Include the derivative of other plots, if appropriate (e.g., square root of time for linear flow)
  - If there is no radial flow period, attempt to type curve match the data
4. Prepare a semi log plot.
  - Use the appropriate time function depending on the length of injection period and injection rate preceding the falloff
  - Draw the semi log straight line through the radial flow portion of the plot and obtain the slope of the line
  - Calculate the transmissibility
  - Calculate the skin factor and skin pressure drop
  - Calculate the radius of investigation
5. Explain any anomalous data responses. The analyst should investigate physical causes other than reservoir responses.
6. All equations used in the analysis must be provided with the appropriate parameters substituted in them.

Note: Tests conducted in relatively transmissive reservoirs are more sensitive to the temperature compensation mechanism of the gauge, because the pressure buildup response evaluated is smaller. For this reason, the plot of the temperature data should be reviewed. Any temperature anomalies should be noted to determine if they correspond to pressure anomalies.